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FIGURE LIST

TABLE LIST

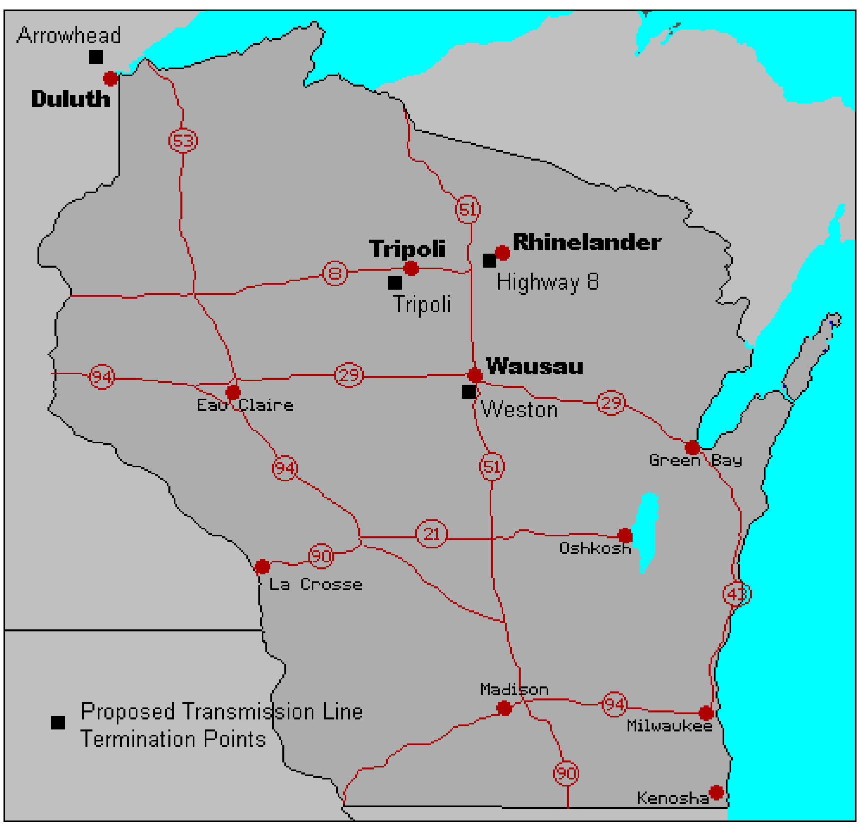
Before the
Public Service Commission of Wisconsin

APPLICATION FOR A CERTIFICATE
OF PUBLIC CONVENIENCE AND NECESSITY

INTRODUCTION

Wisconsin Public Service Corporation (WPSC) and Minnesota Power (MP), referred to jointly as Applicants, propose to construct, operate and maintain a 345 kV electric transmission line between the Weston Power Plant near Wausau, Wisconsin and the Arrowhead Substation near Duluth, Minnesota. WPSC also proposes to construct a 345/115 kV substation, located near Tripoli, Wisconsin and a 115 kV electric transmission line between the Tripoli substation and an existing substation located in Rhinelander, Wisconsin. MP will undertake construction of the 345 kV line from Duluth, Minnesota to Ladysmith, Wisconsin, and WPSC will be responsible for the construction of the remainder of the project. Figure 1 identifies the locations of the termination points for the proposed facilities.

Figure 1 Proposed Termination Points



Wisconsin Public Service Corporation is a public utility corporation organized and existing under and by virtue of laws of the State of Wisconsin with its principal office at 700 North Adams Street, Green Bay, Wisconsin. Wisconsin Public Service Corporation is engaged in, among other functions, the business of providing electric utility service in the north central and north eastern areas of the State of Wisconsin and in a portion of the Upper Peninsula of the State of Michigan. In the process of providing electric utility service, Wisconsin Public Service Corporation has annual gross electric revenues exceeding $200 million.

Minnesota Power is a public utility corporation organized under Minnesota laws with its principal office at 30 West Superior Street, Duluth, Minnesota. Minnesota Power is engaged in, among other functions, the business of providing electricity in north and parts of central Minnesota. Superior Water, Light and Power, a wholly owned affiliate of Minnesota Power, provides electricity, water and natural gas service to customers in part of northwest Wisconsin.

The applicants believe and so allege that the facilities herein proposed are necessary and in the public interest in order to improve the reliability of the electric power supply to customers in northwest and north-central Wisconsin, to all customers of Minnesota Power and Wisconsin Public Service Corporation, to all electric power customers in Wisconsin, and to all electric power customers in the Upper Midwest, and that the general public interest, convenience and necessity require this project. The project will not impair the efficiency of the service of the Applicants, it will not provide facilities unreasonably in excess of probable future requirements, and it will not add to the cost of service without proportionately increasing the value and quality thereof. Wherefore, Wisconsin Public Service Corporation and Minnesota Power respectfully request that the Commission issue a certificate authorizing the construction of the facilities herein applied for.

Dated the ______ day of ____________________, 1999
WISCONSIN PUBLIC SERVICE CORPORATION
MINNESOTA POWER

____
Larry T. Borgard
Vice President – Transmission
Wisconsin Public Service Corporation

____
Donald J. Shippar
Senior Vice President – Customer Services and Delivery
Minnesota Power

CHAPTER 1 PROJECT OVERVIEW

The main element of this project is the construction of a high capacity 345 kV transmission circuit to significantly strengthen the bulk transmission system serving the North Central region of the US and Central Canada. The line would be built between the strong electrical systems of Central Wisconsin and Northeastern Minnesota, and would provide a second high capacity route for electric energy to traverse the Wisconsin – Minnesota transmission system interface.

In addition, a new 345/115 kV substation would be constructed near Tripoli, Wisconsin with a new 115 kV transmission line extended to the local load serving facilities in the Rhinelander, Wisconsin area.

The following sections summarize the physical characteristics of each project component.

1.1 Weston to Arrowhead 345 kV Line

The 345 kV line would consist of a two-conductor bundle per phase with a subconductor spacing of 18 inches. Approximately 10 miles of the line beginning at the St. Louis River would utilize 1272 kcmil ACSR “Bittern” conductor. The balance of the line would utilize 954 kcmil ACSR “Cardinal” conductor. Shielding, communication, and control capability would be provided utilizing an optical ground wire. Route options under consideration for the 345 kV line include double circuit configurations with existing transmission lines, single circuit configurations parallel to existing transmission lines, railroads, pipelines, and other developed corridors, and single circuit configurations routed through less developed lands.

The existing transmission lines that may be double circuited with the 345 kV line have operating voltages of 46 kV, 69 kV, 115 kV, 161 kV, and 345 kV. In cases where the new line is standing alone or running parallel to an existing line, steel H-Frame structures or single pole davit arm structures would be used. The H-Frame structure would be constructed of weathering steel with an average height of 85 to 95 feet. The single pole davit arm structure would also be constructed of weathering steel with an average height of 90 to 105 feet. Span lengths would average between 800 and 1000 feet for both structures. In situations where the new line would be double-circuited with an existing transmission line, a single pole, double circuit davit arm structure would be used. Weathering steel would again be used for this structure design with an average height of 125 to 135 feet.

Some route alternatives, near the Weston generating station, would require the relocation of an existing 46 kV transmission line to facilitate the construction of a double circuit 345 kV line. The relocated 46 kV line would have span lengths that average between 300 and 500 feet and structure heights that average between 50 and 60 feet.

1.2 Tripoli to Highway 8 115 kV Line

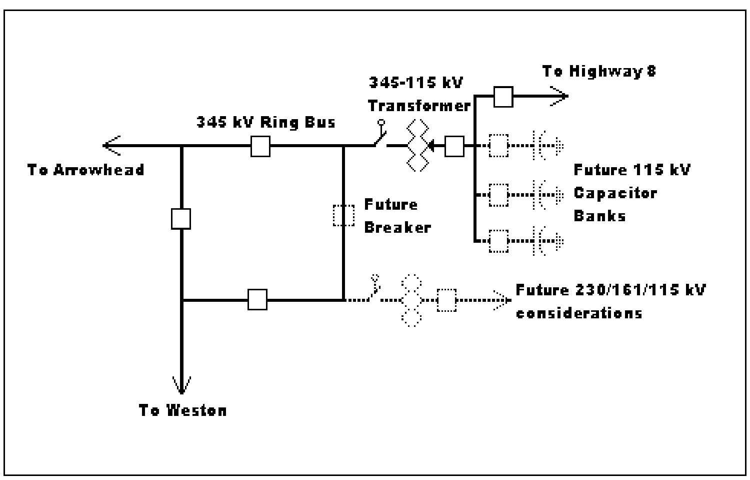
The 115 kV line would be constructed with 795 kcmil ACSR "Drake" conductor. Span lengths will average between 600 and 800 feet. Route options under consideration for the 115 kV transmission line include double circuit configurations with an existing 115 kV line, single circuit configurations parallel to existing and new transmission lines, railroads, and other developed corridors, and single circuit configurations routed through less developed lands.

The 115 kV transmission line would utilize single pole, davit arm structures in cases where the line would be standing alone or running parallel to another transmission line. The structures would be steel pole construction with an average height of 70 to 100 feet. Span lengths would average between 600 and 800 feet. A single pole, double circuit davit arm structure would be used if the new line is double circuited with an existing 115 kV transmission line. The structure would be constructed of weathering steel with span lengths averaging 600 to 800 feet and average structure heights of 85 to 110 feet. Additionally, the new line would have several options that require structures to carry 24.9-kV distribution underbuild. These situations would require mid span wooden distribution poles.

1.3 Tripoli Substation

A 345/115 kV substation would be constructed near the Village of Tripoli. The station would consist of a 345 kV ring bus, a 300 MVA, 345/115 kV transformer and a 115 kV terminal. The 345 kV ring bus would have two terminals through which the Weston – Arrowhead 345 kV line would loop, a terminal for the power transformer and provisions for a future line or transformer connection. The 115 kV side would consist of a single terminal for the new 115 kV line to Highway 8 substation, space for transmission capacitors and provisions for a future ring bus. Figure 2 is a one-line diagram of the proposed substation.

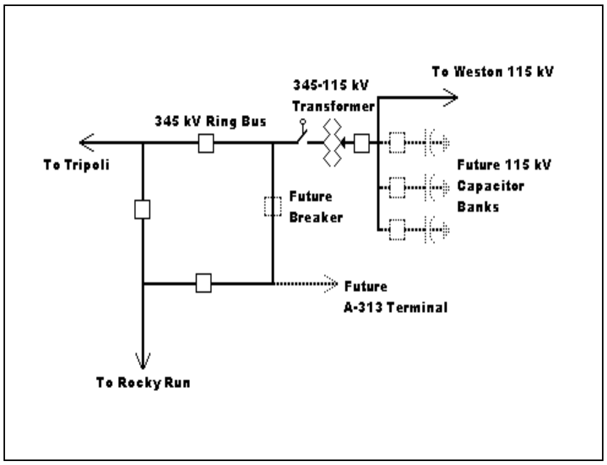
Figure 2 Tripoli Substation



1.4 Weston Substation

A 345/115 kV substation would be constructed at the Weston Power Plant south of Wausau. The station would consist of a 345 kV ring bus, a 300 MVA, 345/115 kV transformer and a 115 kV terminal. The 345 kV ring bus would have two terminals through which the Tripoli – Rocky Run line would loop, a terminal for the power transformer and provisions for a future line or transformer connection. The 115 kV side would consist of a single terminal for a tie to the existing 115 kV switchyard, space for transmission capacitors and provisions for a future ring bus. Figure 3 is a one-line diagram of the proposed substation.

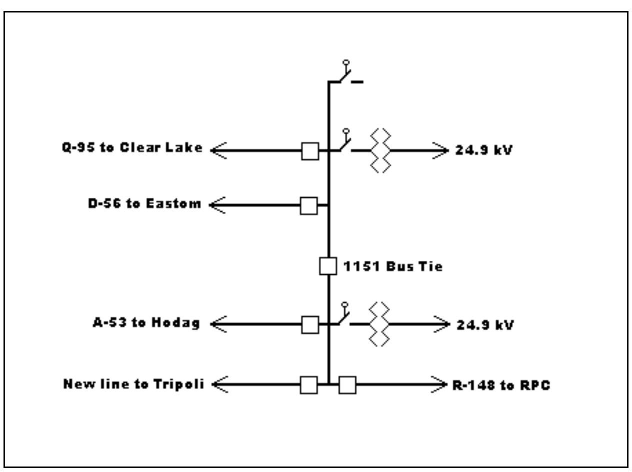
Figure 3 Weston Substation



1.5 Highway 8 Substation

A 115 kV breakered line terminal would be added at the Highway 8 Substation. The 115 kV line from Tripoli would be dead-ended on the existing steel structure. The new terminal would require a breaker and disconnect switches. Figure 4 is a one-line diagram of the proposed substation addition at Highway 8.

Figure 4 Highway 8 Substation



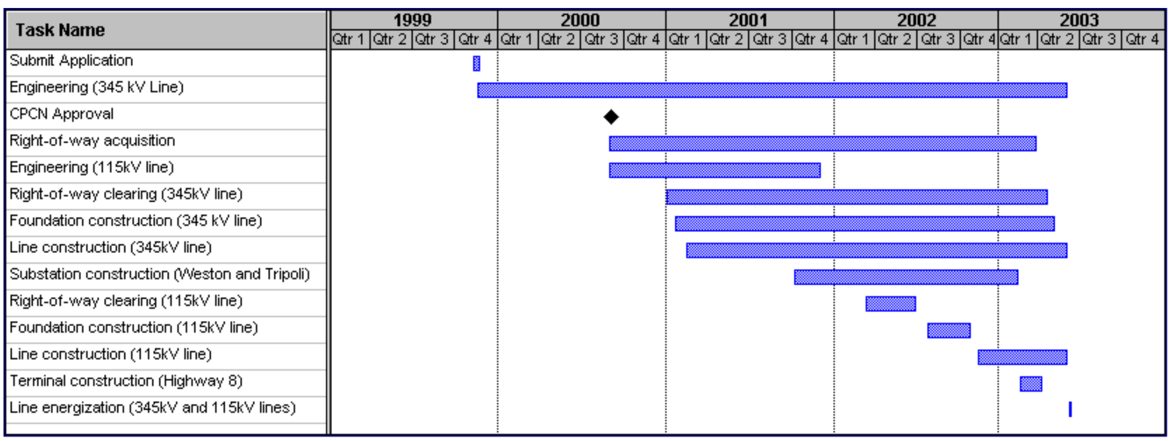
CHAPTER 2 SCHEDULE

The approval and construction of the proposed facilities is expected to follow this schedule:

Submit Application	November, 1999
Public Hearings	June, 2000
PSCW Order	September, 2000
Start Right of Way Acquisition	September, 2000
Commencement of Construction	January, 2001
Completion of Construction	May, 2003

The following figure illustrates the various tasks and timelines associated with the project.

Figure 5 Project Tasks and Timelines



CHAPTER 3 ARROWHEAD – WESTON STATEMENT OF NEED

3.1 Historical Overview of Electric Reliability

The extra high-voltage (EHV), 230 kV and above, bulk power transmission system in the Upper Midwest was designed and constructed in a period that extended into the 1970s. The EHV transmission interconnections that were developed between individual power systems made possible the integrated operation of multiple systems with subsequent reliability and economic benefits. The prevalent economic benefit has been from a reduction in the generation capacity required to maintain electric service under a myriad of operating scenarios. The predominant reliability benefit has accrued from the adequacy of the bulk power system to transfer power from generation stations to load centers and the security of the bulk power system to deliver emergency energy during times of critical system contingencies and high electrical consumption. Throughout the history of the electric utility industry, the establishment of transmission interconnections has dramatically increased reliability and reduced overall operating costs.

The transmission interconnections to neighboring regions have allowed Wisconsin to access installed generation capacity within those neighboring regions and effectively reduce generation reserve margins from nearly 30% to 18% without compromising electric service reliability. This means that for 10,000 MW of electric load, only 11,800 MW (10,000 times 118%) of generation rather than 13,000 MW (10,000 times 130%) of generation are required to maintain the same level of reliability. The benefit of transmission interconnections to neighboring regions is the reduction of 1200 MW (13,000 less 11,800) of installed generation capacity within Wisconsin. At a construction cost of $300 - $400/kW for combustion turbine generation capacity, 1200 MW of generation would cost approximately $360 – $480 million to build.

In recent years however, the reliability margins inherent to the bulk power transmission system have sufficiently eroded such that the ability to maintain reliable electric service is severely compromised. Market driven changes of transmission usage patterns that emerged following FERC's Open Access Order Nos. 888 and 889, sustained load growth, and unplanned generation resource outages have all contributed to the erosion of the reliability component of the bulk power system. Market-based transactions increasingly compete with reliability-based usage for limited transmission system availability. The North American Electric Reliability Council (NERC) recognized the changing landscape of the bulk power transmission system in its _1998 – 2007 Reliability Assessment Report._ NERC states:

> *Transmission systems [are] increasingly challenged to accommodate demands of evolving competitive electricity markets. Market-driven changes in transmission usage patterns, the number and complexity of transactions, and the need to deliver replacement power to capacity-deficient areas are causing new transmission limitations to appear in different and unexpected locations.* (p.6)

Electric supply adequacy could deteriorate in the long term if development of additional generating and transmission capacity does not keep pace with growing customer demand. (p.6)

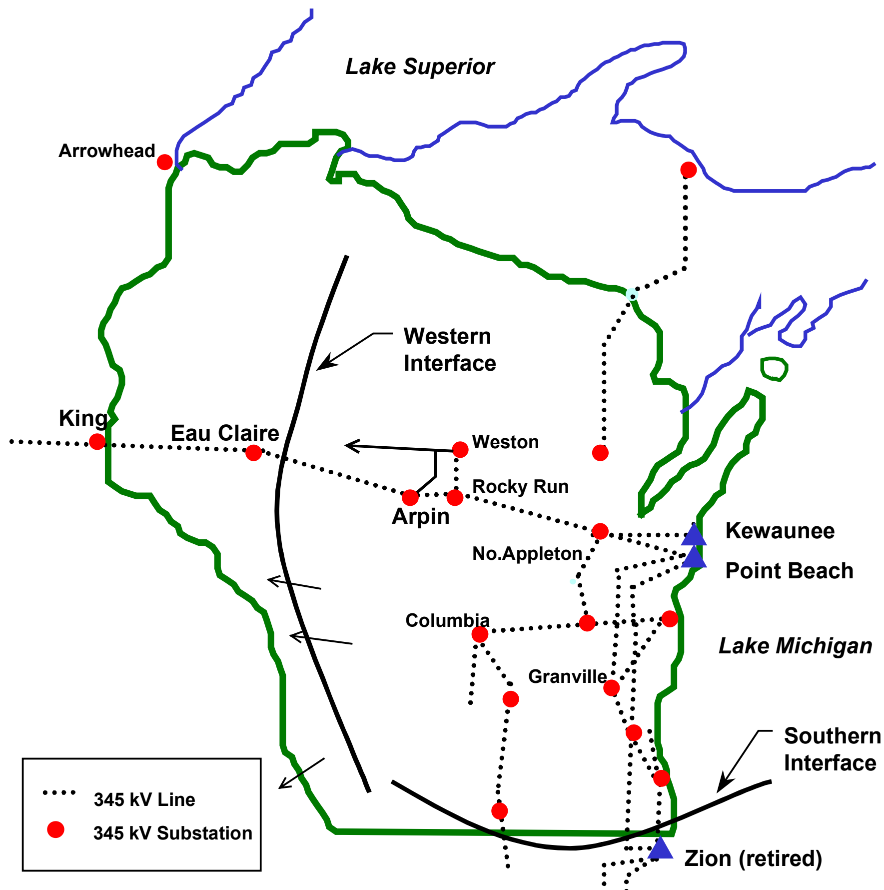
Very few bulk transmission additions [are] planned. Only 6,588 miles of new transmission (230 kV and above) are planned throughout North America over the next ten years. This is significantly lower than the additions that had been planned five years ago. The majority of the proposed transmission projects are for local system support. As the demand on the transmission system continues to rise, the ability to deliver remote resources to load centers will deteriorate. New transmission limitations will appear in different and unexpected locations as the generation patterns shift to accommodate market-driven energy transactions and new independent generators. Delivering energy to deficient areas may become more difficult. (p.7)

As the capability of the bulk transmission system is increasingly utilized to support non-traditional obligations, the reliability of the electric supply system will continue to decline.

3.2 Recent Reliability Problems in Wisconsin

Wisconsin is confronted with certain geographical limitations that hinder its ability to rely on external generation resources in emergency situations. Wisconsin's ability to access generation resources to the north and east is effectively obstructed by Lakes Superior and Michigan. The only meaningful access to external resources is via the transmission interconnections to the west and south of Wisconsin. To the west, Wisconsin is weakly interconnected with Minnesota and the remainder of the Mid-Continent Area Power Pool (MAPP) through a single 345 kV transmission line between the Twin Cities and central Wisconsin and a number of lower voltage facilities whose primary purpose is to serve local area load. To the south, Wisconsin is interconnected with northern Illinois and the remainder of the Mid-America Interconnected Network (MAIN) through three 345 kV transmission lines and a single 138 kV transmission line. In whole, these transmission interconnections constitute the entire transmission "interface" between Wisconsin and external regions. A map of Wisconsin's existing high-voltage transmission system is shown below.

Figure 6   Existing EHV Transmission System



The ability to transport electric capacity and energy over the southern and western transmission interfaces to maintain reliability is not without limitation. The capability of each interface is limited by the physical characteristics of the transmission facilities that comprise the interface and by the stability characteristics of the integrated generation and transmission system. The capability of a transmission interface is dependent on a host of factors including the demand for electricity, electrical load patterns, generation dispatch, transmission system topology, and simultaneous transactions between utilities. Each of these factors is continually changing; consequently, the western and southern transmission interface capabilities are also continually changing.

The inter-relationship between the generation and transmission system was clearly demonstrated during 1997 and 1998 when the Midwest region experienced lower than expected reliability levels due to the potential for generation capacity shortfalls. The unavailability of several large base-load generation units not only reduced the capability of the regional transmission system but also increased the usage of and dependence on the transmission system as power delivery entities purchased replacement energy from distant sources. This situation was most notable in eastern Wisconsin during the spring of 1997 when all three of Wisconsin's nuclear generating units were unavailable. Access to external generation resources to replace the nuclear units through the western and southern interfaces was essentially non-existent due to limitations caused by other generator outages and increased use of the system to support third party market activity. The unavailability of parochial generating capacity, coupled with severely constrained transmission interfaces raised several reliability issues in Wisconsin and surrounding regions.

The reliability problems caused by the lack of sufficient interface capacity have become apparent on several occasions in recent years.

- During two particularly hot days in July 1995, the generation reserve margins, which the Eastern Wisconsin Utilities strive to maintain, for reliability purposes, became alarmingly low when the only major transmission facility interconnecting Wisconsin to Minnesota (the Eau Claire – Arpin 345 kV line) was out of service on July 13th and a nuclear unit in Wisconsin was out of service on July 14th.
- Generation capacity reserve margins were well below levels needed for adequate reliability throughout the spring and summer of 1997, and periodically during the summer of 1998.
- On June 11, 1997, an outage of the Wisconsin-Minnesota 345 kV transmission interconnection during the middle of the night caused by large southward power transfers from MAPP resulted in a scramble by utility operators to maintain the stability of the bulk electric system. As a result of that experience, a new, lower transfer limit (775 MW) on the transmission interconnection was established.
- On June 25, 1998, an outage of that same 345 kV transmission interconnection occurred while several transmission facilities in the Midwest were already out of service due to weather related events. The end result was that a large region including some parts of western Wisconsin was electrically separated from adjacent regions, generation within the isolated areas was forced out of service, blackouts occurred in parts of Canada, service to some industrial customers in Minnesota was interrupted, and the integrity of the electric system in the upper Midwest was severely jeopardized.
- More recently, on March 15, 1999, a scheduled maintenance outage of the Arpin-Rocky Run 345 kV transmission line had to be cancelled when flows across the Wisconsin-Minnesota 345 kV interconnection overloaded the 345/138 kV transformer at Arpin, causing damage to a portion of the transformer apparatus.
- On several occasions in June of 1999, transmission system operators experienced heavy flows on the 345 kV line between Minnesota and Wisconsin in excess of the line's capability. Operators could not restore the line's flow to safe level within a reasonable amount of time and exceeded operating reliability criteria established by NERC.

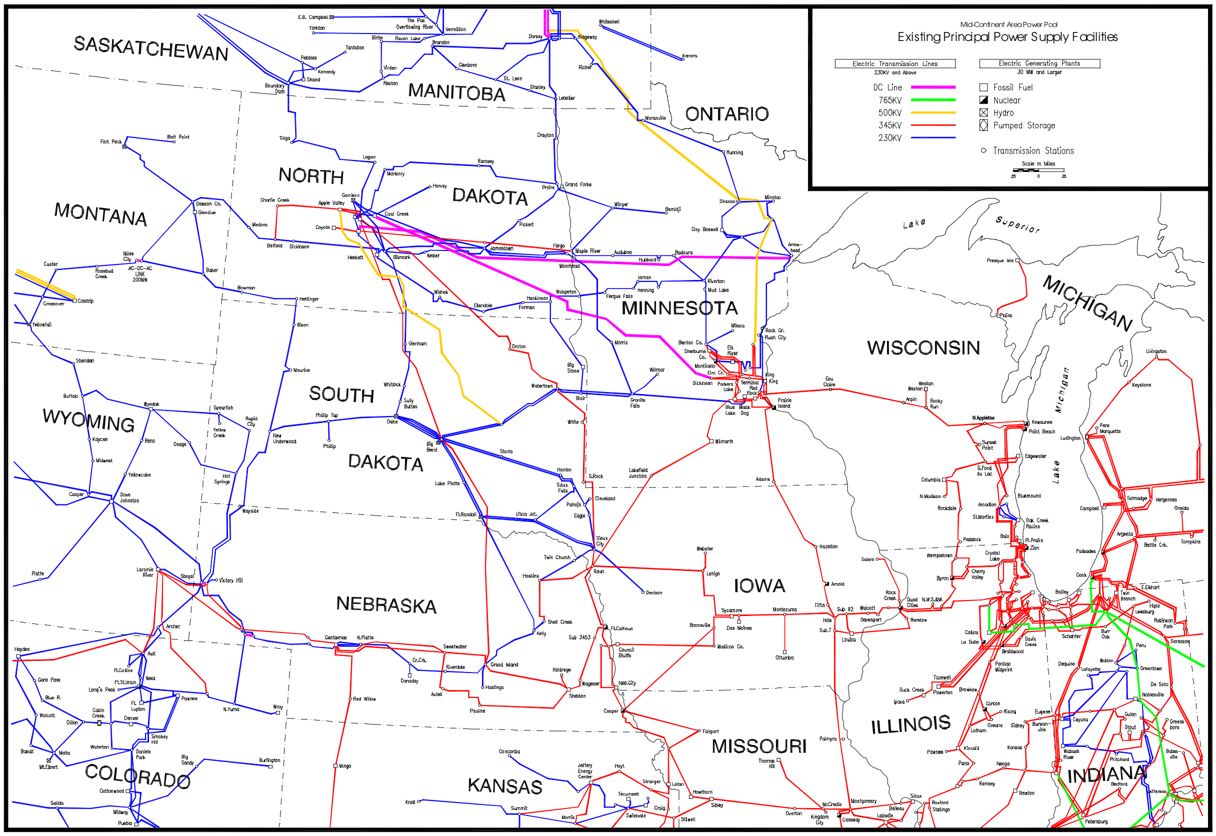
These examples are a mere fraction of the reliability challenges faced by Wisconsin electric utilities in recent years. Appendix G of this application is a compilation of news articles written by various authors on the struggle to maintain reliable electric service through periods of high demand and scheduled transmission and generation maintenance. Appendix G is a testimonial of the critical need to re-establish reliability margins within the bulk power transmission grid.

3.2.1 Regional Reliability Issues

The electrical grid transporting energy throughout the Midwest region consists of an infrastructure of transmission and distribution lines. The EHV portion of this grid, operating at levels from 230 kV to 500 kV, provides the ability to move electric energy from remote generating facilities to electric customers. These lines also provide emergency support to the region during times of major generating station and transmission line outages. Distribution lines connect the substations with the customer. Most customer outages occur because of distribution problems, and are localized. However, a transmission outage could affect many customers at one time over a wide geographic region.

The upper Midwest grid is connected directly to the state of Wisconsin through a single 345 kV transmission line from the Twin Cities area to Eau Claire, and continuing on to eastern Wisconsin. The only other EHV transmission lines supporting Wisconsin are between Illinois and eastern Wisconsin. Since the Twin Cities – Eau Claire 345 kV line is the only major tie line connecting Wisconsin to the west; it is normally heavily loaded. Loading has increased drastically from the early 1990s to the mid 1990s. Over the years, additional operating restrictions have been placed on the network in order to restrict loading on the Twin Cities - Eau Claire 345 kV line. The additional restrictions have limited the transmission transfer capability of not only Wisconsin but also the entire Midwest region. The Twin Cities – Eau Claire 345 kV line is a “weak link” in the upper Midwest EHV network which manifests itself as overloaded lines, inadequate voltage support, forced curtailments of energy deliveries, and the risk of regional grid failure. Figure 7 demonstrates the lack of EHV transmission facilities between eastern Wisconsin and Minnesota in relation to other areas within the Upper Midwest.

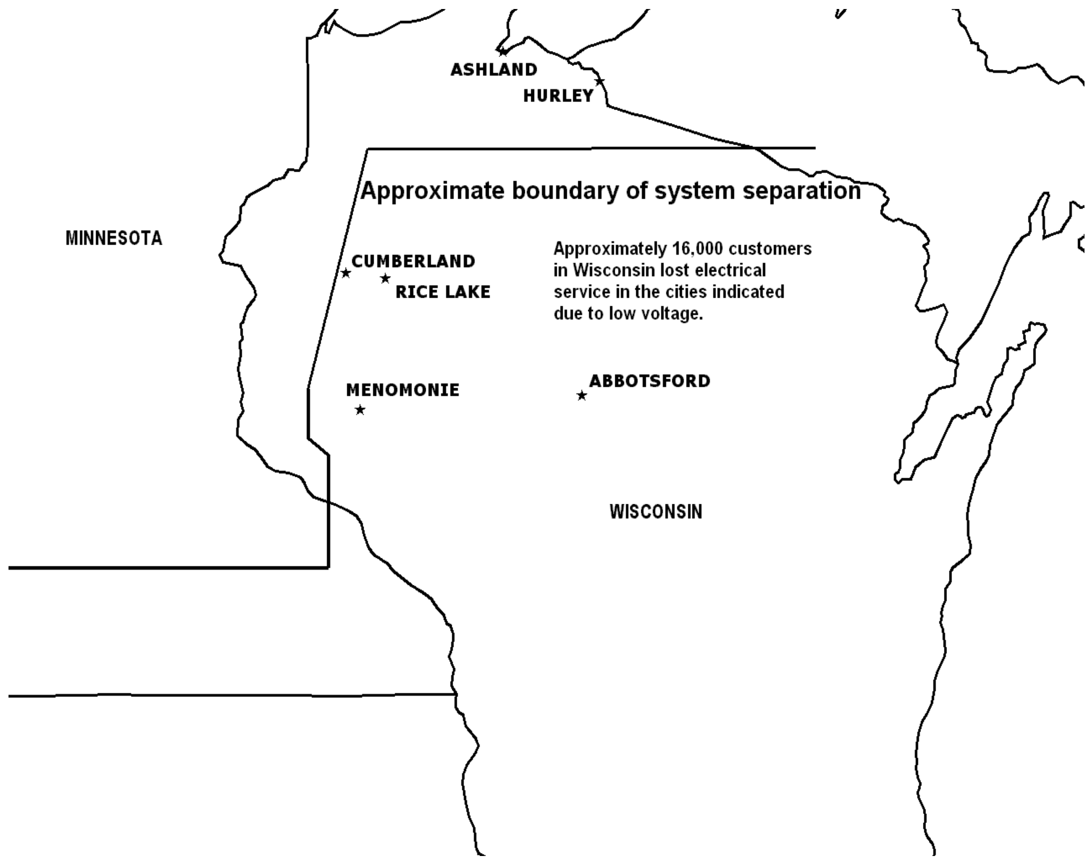
Figure 7 Upper Midwest EHV Transmission System



The risk of a wide spread blackout is illustrated by the events that occurred on June 25, 1998. Loading on the Twin Cities interconnections was approximately 1578 MW, near the established transfer limit. Lightning from a severe thunderstorm over the Twin Cities area caused the Prairie Island to Byron 345 kV line to trip out of service at 1:34 AM. Loss of this line immediately placed the system in an insecure state, with loading beyond the capability of the system. Before the operators were able to restore this line to service, lightning from the same thunderstorm caused the Twin Cities – Eau Claire 345 kV line to trip out. Following failure of this transmission line, voltage in western Wisconsin began to collapse, the remaining lower voltage lines connecting Minnesota with the Wisconsin system began tripping as they became overloaded, and the cascade tripping continued until the entire northern MAPP region was separated from the interconnection. This left Manitoba, Saskatchewan, northwestern Ontario, North and South Dakota, Minnesota, and parts of northwestern Wisconsin electrically isolated from the interconnection. Four minutes later, the North Dakota system separated from Minnesota, resulting in yet another electrical island. This resulted in the loss of approximately 3900 MW of generation and interruption of service (a "blackout") to approximately 300 MW of load in the MAPP region. The northwestern Ontario system experienced a complete black out with the loss of

270 MW of generation and interruption of service to 650 MW of load. The MAPP system, including sections of northwestern Wisconsin (shown in Figure 8), nearly collapsed due to low voltages, which would have resulted in a massive blackout. It was fortunate that several low voltage lines automatically re-closed and stayed closed, allowing other lines to be returned to service. These initial line closings did not happen by design or operator action, but they did allow the system operators to regain control of the situation and avoid a complete regional blackout. This event demonstrates the critical importance of a tightly interconnected bulk power transmission system and the ramifications of "electrical islands" that are no longer connected to the interconnected regional grid.

Figure 8 Approximate Boundary of June 25, 1998 System Separation



A year earlier, on June 11, 1997, a similar incident occurred which also resulted in the near collapse of the regional power grid. The Twin Cities - Eau Claire 345 kV line tripped out of service due to lightning, which resulted in a shift of power flow to the south of the Twin Cities, causing an overloading of the Cooper to St. Joseph 345 kV line between Nebraska and Missouri. The overload caused low voltages and abnormally high electric loading on the transmission system throughout southwestern Minnesota, southwestern Wisconsin, eastern Iowa and northern Illinois. If the Cooper to St. Joseph 345 kV line would have tripped out of service due to the heavy electric flows, the remaining lines to the south and east of Nebraska would have likely tripped out of service resulting in a major regional power disruption leading to blackout conditions.

There were a number of incidents during the summer of 1999 when electric flow on the Twin Cities – Eau Claire 345 kV line exceeded its security limit and line loading relief procedures failed to produce relief in a timely fashion. During these occurrences, the entire upper Midwest region was at risk and the reliability of the grid was severely compromised for several hours until the power flow across the line was reduced. Since this is the only EHV transmission line connecting Wisconsin to the west, a small percentage of power from most generating stations throughout the region flow over this line, which together result in a large amount of power flow that has been difficult to control.

An additional 345 kV line connecting Wisconsin to the west line will strengthen the electrical interface between Minnesota and Wisconsin by providing an additional path for power to flow during normal and emergency conditions. This additional path will relieve power flow on critical facilities following loss of the Twin Cities – Eau Claire line or other critical facilities. An additional interconnection to the west will also permit Wisconsin access to regional energy resources during transmission and generation emergencies within the state.

Following engineering analysis of the 1997 and 1998 heavy loading incidents, additional operating procedures and control modifications were implemented to minimize the likelihood of a reoccurrence. Most of these procedures work by placing additional restrictions on the network and by limiting generator output throughout the region in order to restrict flow between Minnesota and Wisconsin. Other procedures call for emergency manual reduction of generation in the Twin Cities area in order to return the system to a secure condition following a trip of the Twin Cities - Eau-Claire line or the Prairie Island – Byron line. Although the operating procedures help maintain operational control of the interface, they also significantly reduce the reliability benefit of the interconnected system. In addition, the operating procedures do not completely eliminate the risk of system failure resulting from this weak link in the grid. For example, during high loading conditions on the Twin Cities – Eau Claire 345 kV line, the line is prevented from quickly reclosing after a trip from lightning until the power system can be manually adjusted through operator action in order to reduce the “electrical angle” or system separation between Eau Claire and Arpin. This procedure is necessary to protect physical equipment on generators at the Weston power plant near Wausau. Procedures established by NERC permit 30 minutes to restore the system to a secure condition. If a second event occurs within this 30-minute period, and the system has not yet been secured, the type of system failures described above can occur. An additional interconnection from the west will permit faster reclosing of the Eau Claire – Arpin line over a wider range of system conditions, reducing the risk of another event occurring before the system is secured.

Since the Minnesota – Wisconsin interface is often operated at or near its security limit, a trip of either the King – Eau Claire line or the Prairie Island – Byron line, with failure to reclose, will leave the system operating above the security limit. If another event occurs before the system is restored, the Minnesota – Wisconsin interface can fail, resulting in conditions similar to July 25, 1998. In order to manage this situation, emergency procedures are in place to manually reduce Twin Cities generation in order to reduce loading on the system as fast as possible. NERC criteria permits 30 minutes to restore the system to a secure state. Strengthening the interface will permit operation over a wider range of operating conditions before such emergency measures are necessary.

Unanticipated system conditions that cannot be studied before the fact, or control failures can also add to the risk of operating this critical interface continuously near its security limit. Failure of the Minnesota – Wisconsin interface can have more severe consequences than the failure of other interfaces in the upper Midwest region. Failures of most other interfaces within the upper Midwest will result in more localized problems, or affect a much smaller part of the region.

3.3 Review of Wisconsin's transmission Interface Infrastructure

In response to the reliability issues and the potential for capacity shortages, Wisconsin's Governor Tommy Thompson, on June 24, 1997 requested that the state's electric utilities convene a task force to analyze and make recommendations on several issues including the regulatory review process for new transmission and generation and implementation measures to avoid reliability issues in the future. This "ad-hoc" joint utility group was the predecessor of the Wisconsin Reliability Assessment Organization (WRAO). In September of 1997 the joint utility group[1] responded to the Governor and recommended additional generation capacity in eastern Wisconsin and additional transmission capacity between eastern Wisconsin and other regions.

In the first quarter of 1998, the WRAO formed a transmission analysis task force to study the regional constraints affecting Wisconsin's ability to import energy and to investigate system reinforcement alternatives to alleviate those constraints. The transmission task force adopted the acronym WIREs (Wisconsin Interface Reliability Enhancement study) and included participation from electric utilities in Illinois, Iowa, Minnesota, Wisconsin, Michigan and the Canadian Province of Manitoba. Two reliability councils of NERC, MAPP and MAIN, endorsed the WIRE study group as a regionally recognized study effort. Regulatory agencies from Illinois, Iowa, Minnesota, and Wisconsin also participated as ex-officio members.

The WIRE study group designed a two-phase study effort to examine the existing limitations on Wisconsin's western and southern transmission interfaces. The Phase I

[1] The Joint Utility Group consisted of the following entities: Dairyland Power Cooperative; LS Power, LLC; Madison Gas and Electric Company; Northern States Power Company; Municipal Electric Utilities of Wisconsin; Superior Water, Light, and Power Company (Minnesota Power); Wisconsin Electric Power Company; Wisconsin Federation of Cooperatives; Wisconsin Power and Light Company; Wisconsin Public Power, Inc.; and Wisconsin Public Service Corporation

study effort, culminating in August of 1998 with the release of the *Wisconsin Interface Reliability Enhancement Study Phase I* report, consisted of a screening analysis to determine regional transmission constraints and the identification of a set of twelve representative transmission reinforcement alternatives. The Phase I study effort also constituted the basis for a September 1, 1998 report developed by the Public Service Commission of Wisconsin (PSCW) for the Wisconsin Legislature on the regional electric transmission system. Wisconsin Act 204 mandated the PSCW report and also enacted changes to the regulatory filing requirements for new transmission and generation infrastructure located within Wisconsin.

The Phase II study effort, completed in June of 1999, culminated with the release of the *Wisconsin Interface Reliability Enhancement Study Phase II* report, refined the Phase I results by further defining relative performance differences between seven alternative transmission reinforcement plans. The Phase II study consisted of a regionally comprehensive transmission planning analysis that included dynamic stability, voltage stability, sensitivities, switching considerations, and a detailed construction cost and loss analysis.

Coincident with the WIREs Phase II study effort, the WRAO initiated a screening environmental analysis of the seven transmission reinforcement plans under consideration by the WIRE study group. In addition, the WRAO studied several policy criteria associated with transmission system expansion such as geographic diversity, constructability, and system development and regional reliability benefits. On June 14, 1999, the WRAO filed with the Public Service Commission the *Report of the Wisconsin Reliability Assessment Organization on Transmission System Reinforcement in Wisconsin*. The report states:

> *After careful consideration of the implications of the seven transmission [reinforcement] plans, based upon the Phase II WIREs group analysis of performance and cost, the environmental screening analysis, and several policy criteria, the WRAO [has] concluded that plan 3j (Arrowhead – Weston 345 kV) is the best plan for achieving the multiple objectives of this study effort. Plan 3j meets all technical criteria and appears to have reasonable routing alternatives. It also provides geographic diversity, low system losses, and is capable of being constructed with an acceptable cost and schedule.* (p.4)

3.4 Engineering Analysis

The WIRE study group identified a need to perform a comprehensive review and analysis of the regional transmission limitations that restrict the capability of Wisconsin's western and southern interfaces. In addition, the group planned to perform a comprehensive review of various reinforcement alternatives that would address the limitations. The comprehensive review was to include a full power flow analysis which includes both thermal and voltage limitations, a transient stability analysis, a voltage stability analysis, a full economic analysis, and sensitivities to input assumptions such as load level and generation dispatch profiles. Given the resource requirements necessary to undertake such an analysis, the group devised a multi-phase study effort. The Phase I study effort consisted of a screening analysis to identify regional constraints and a representative set of potential transmission reinforcements. The Phase I study effort is considered a "screening" analysis because it focused primarily on thermal (or facility overload) constraints to transfer capability. The Phase II study effort refined the results of the Phase I study, developed transmission reinforcement plans, and considered voltage and dynamic stability simulations.

3.4.1 WIREs Phase I Study Effort

Study Methodology

The objectives of the Phase I study effort were to:

1. Identify the regional transmission constraints that limit the import capability into Wisconsin.
2. Define transmission reinforcement alternatives which provide the following transfer capabilities (the 2k/2k/3k objective):
   - 2000 MW of non-simultaneous transfer capability across the western interface and the southern interface.
   - 3000 MW of simultaneous transfer capability into eastern Wisconsin.

Preliminary reliability (loss of load expectation) calculations performed by the WRAO established a need to evaluate eastern Wisconsin's import capability up to the 2000 MW and 3000 MW targets (collectively known as the 2k/2k/3k objective).

To obtain these objectives, the WIRE study group utilized a modified 2002 summer power flow base case from the NERC power flow library. Modifications to the base case include:

- the addition of facilities in Wisconsin identified as preferred solutions to local load serving problems in Advance Plan 8. All facilities added to the base case are expected to be in service by June 1, 2002.
- the addition of facilities that solve local load serving problems in Minnesota, Iowa and Illinois expected to be in service by June 1, 2002.
- an increase in Manitoba Hydro exports to 1950 MW.
- an increase in North Dakota exports to 1800 MW.
- a total of 525 MW of firm transactions into Wisconsin were included in the 2002 base case; 375 MW from the west and 150 MW from the south

A complete list of the transmission facilities added to the 2002 summer model is contained in Appendix A of the WIREs Phase I Study Report. The more notable facilities required for local load serving include:

1. Lockport - Lombard red and blue 345 kV lines (ComEd)
2. Chisago Co. - Apple River 230 kV (NSP/DPC)
3. Baldwin - Marathon City 115 kV Transmission upgrade project (NSP/WPS)

The Phase I study utilized a DC power flow algorithm to determine transfer capability limitations and to measure the transfer capability impacts of the various reinforcement alternatives. Generation resources in western MAPP, used as “sources” to simulate flows across the western interface, were made available through load reduction and the addition of unplanned generating units in North Dakota and Nebraska. Existing generation resources in southern Illinois and the East Central Area Reliability (ECAR) council were used to simulate flows across the southern interface. Generation within the WUMS[2] subregion was reduced proportionally to facilitate the increased imports to create a “sink” for the simulated transactions.

The transfer capability of each interface was determined with a 1000 MW import transaction on the opposite interface. This “bias” insured the 3000 MW simultaneous transfer capability objective when testing each interface to a level of 2000 MW.

The study monitored all transmission system elements 100 kV and above in Wisconsin, Michigan’s Upper Peninsula, Illinois, Iowa, Minnesota, Eastern Missouri and Eastern Nebraska. Only facilities that participated in transfers at levels greater than 3% were considered valid transfer capability limitations. The transfer capability simulations covered single-element contingencies in all of the regions listed above, with the exception of the ComEd service territory. ComEd submitted a contingency list for their facilities that included many multi-element outages consistent with the ComEd planning criteria. In addition, the simulations tested several operating guides that involved facilities in central and southern Wisconsin.

Perhaps the most important consideration of the single-element (first contingency) transfer capability determination is the difference between the power flow model and actual system conditions. The base case power flow model is a “snapshot” of system conditions that assumes a particular generation dispatch, load profile, and transmission system topology; this is referred to as the “n” system state. First-contingency transfer capability studies determine the ability of the system to move power from one point to another assuming that the transmission system topology is perfectly available except for the single transmission element contingency under consideration; this is referred to as an “n-1” system state. In real-time operating conditions however, one or more transmission elements or generating stations could be out of service for maintenance prior to the most limiting contingency. In the operating sense if one transmission element is out of service for maintenance, the “base case system” is in an “n-1” system state and the loss of a single transmission element results in an “n-2” system state. The effect of planning a system to support a particular transfer capability under an “n-1” system state and actually operating in an “n-2 (or higher)” system state is a potential for lower than anticipated transfer capabilities. Because of the extreme variability of actual operating system states, it is not unreasonable to utilize conservative assumptions when determining the amount of transfer capability required for reliability and used in transmission planning studies.

[2] In this document, “WUMS” refers to all load serving entities (LSEs) within the control areas of Wisconsin Electric Power Company, Alliant-East (formerly WPL), Wisconsin Public Service, Madison Gas & Electric, and Upper Peninsula Power Company. WUMS is the acronym for Wisconsin Upper Michigan Systems.

A complete and detailed description of the Phase I study methodology is contained in Chapter 4 of the Phase I WIRE Study Report.

Transmission Constraints Identified

The transfer capabilities of the western and southern interfaces were evaluated by determining the first contingency total transfer capability (FCTTC). The FCTTC of an interface is the maximum transfer capability in megawatts (MW or 1,000,000 watts) that the interface is able to support during the simultaneous outage of another transmission element. Although a discrete value, the FCTTC is representative of the relative strength of a particular interface. The real-time transfer capability of a given interface is a function of several variables and could be higher or lower than the FCTTC calculated from a particular transfer capability study which is merely a “snapshot” of expected system conditions some time in the future.

The FCTTC of the western and southern interfaces of the 2002 system with just local load serving facility additions are 810 MW and 1000 MW respectively (each calculated with a 1000 MW bias on the opposite interface for a simultaneous import capability of 1810 MW and 2000 MW, respectively). Transmission facilities such as the Arpin – Eau Claire 345 kV transmission line (Wisconsin), the Eau Claire – Wheaton 161 kV line (Wisconsin), the Electric Junction – Plano Red 345 kV line (northern Illinois), and the Goodings Grove – Lockport Red 345 kV line (northern Illinois) were all found to limit Wisconsin’s import capability. Extensive use of the Arpin area operating guide[3] is required to attain these FCTTC levels for the outage of the King – Eau Claire – Arpin 345 kV facility. The Arpin area operating guide consists of opening as many as four substation breakers to prevent transmission lines from overloading during specific transmission line outages or overload conditions. Although implementation of the guide maintains security of the system during transfers, it also compromises the reliability of looped local load serving systems by making them radial. Without the Arpin operating guide, transfer capability on both the western and southern interfaces is limited to 0 MW. In fact, without the operating guide, an outage of the King – Eau Claire – Arpin 345 kV line will cause several transmission facilities to load well in excess of their emergency ratings without any transfers at all. Facilities in the Eau Claire area, for example, load to nearly 150% of their emergency limits under this scenario. If allowed to persist, an overloaded facility will eventually “trip” out of service causing other facilities to overload and trip out. This cascading situation will ultimately lead to blackout conditions on certain portions of the system. Appendix E, pages E-1 and E-64, of the WIREs Phase I study report contain detailed power flow output from the transfer capability simulations of the 2002 power flow model without additional reinforcements.

[3] An operating guide is a set of pre-defined procedures used to return the system to a safe operating state. Most operating guides are only utilized during the amount of time required to return an outaged transmission element to service or to cut transactions that contribute to the overloaded facility. Operating guides are not designed to support continuous system operations.

Directly related to the loss of the King – Eau Claire - Arpin 345 kV facility is the Arpin phase angle limitation. Manifested as a flow limit, the Arpin phase angle limitation is a proxy for the maximum amount of stress induced on the Weston generators when any portion of the King – Eau Claire – Arpin 345 kV line is switched. The sudden loss of any portion of the King – Eau Claire – Arpin 345 kV line results in a system "separation" between MAPP and eastern Wisconsin. This separation is measured in degrees at the Arpin substation and referred to as the Arpin phase angle. When the 345 kV line is re-closed across this separation, generators in the vicinity of the western interface instantaneously adjust their power output to compensate for the separation. This instantaneous change in power output places mechanical stress on the generator shaft and turbine blades contributing to a loss of life on the unit. The current operating procedure requires an Arpin phase angle of no more than 60 degrees prior to re-closing the line. Because of the difficulty in reducing the phase angle to 60 degrees and in an attempt to manage the post-contingency phase angle separation, an Eau Claire - Arpin 345 kV flow limit (pre-contingency) of 775 MW has been established. The Phase I WIRE study examined the Arpin phase angle limitation as a proxy for stress on the Weston generators; the Phase II WIRE study focused on a more direct measure of generation stress by calculating the instantaneous change in power output (delta-P) of the Weston #3 generation unit.

The Arpin flow limit, although required to maintain system security, has resulted in numerous instances of transmission line loading relief[4] procedures to return the facility within a safe operating state. In 1997, nearly 280 episodes of line loading relief were required to maintain security of the system; in 1998, 76 episodes occurred. The existing King – Eau Claire – Arpin 345 kV facility is the weakest link within the upper Midwest transmission grid and limits the ability to move energy in nearly 2300 transfer directions. Concerned about the number of transmission line loading relief procedures on this single facility, NERC's Congestion Management Working group (CMWG), in May of 1999, conducted a review of the King – Eau Claire – Arpin 345 kV limitation, short term operating steps, and long term transmission reinforcements to alleviate the constraint. The NERC CMWG found that MAIN acted properly in their management of the Arpin – Eau Claire 345 kV facility and that operational steps (the Arpin operating guide) have been implemented to improve the operational limits on the line. Although the number of line loading relief episodes is down for the first two quarters of 1999, transmission system operators have further restricted access to the interface to keep loading within safe limits. Unfortunately, restricted access to external resources during emergencies has significantly reduced the reliability of the electric supply system within Wisconsin and neighboring regions.

[4] The line loading relief procedure is a method used to determine individual transactions that contribute to an overloaded facility and the curtailment of those transactions to provide relief.

Reinforcement Options Considered

Because the FCTTCs determined in the transfer capability analysis of the 2002 system with just local load serving facility additions did not meet the transfer capability objective of 2000 MW on each interface, several transmission reinforcement options were considered. As the transmission system was stressed at increasing import levels, additional transmission constraints arose prior to reaching the transfer capability objective. Several constraints, which were frequently identified in the transfer capability analysis, are shown in Table 1. Although some of these limitations are alleviated with relatively inexpensive equipment modifications or upgrades, several indicate the need for system expansion.

Table 1 Identified Constraints

Constraints	State	Constraints	State
Arpin Interface Operating Flow Limit	Wisconsin	Pulliam 138/115 kV Transformer	Wisconsin
Eau Claire-Wheaton 161 kV line	Wisconsin	Rocky Run-Whiting 115 kV line	Wisconsin
Wheaton-Wheaton Tap 161 kV line	Wisconsin	Turkey River-Cassville 161 kV line	Iowa/Wisconsin
Wheaton-Elk Mound 161 kV line	Wisconsin	Paddock-Wempletown 345 kV line	Wisconsin/Illinois
Wien-T Corners 115 kV line	Wisconsin	Lore-Turkey River 161 kV line	Iowa
Arcadian 345/230 kV Transformer	Wisconsin	Kelly-Whitcomb 115 kV line	Wisconsin
Electric Junction-Plano 345 kV line	Illinois	Weston 345/115 kV Transformer	Wisconsin
Itasca-Lombard Breaker	Illinois	Sigel-Arpin 138 kV line	Wisconsin
Seneca-Genoa 161 kV line	Wisconsin	Forest Junction-Highway V 138 kV line	Wisconsin
Columbia-South Fond Du Lac 345 kV line	Wisconsin	Arpin 345/138 kV Transformer	Wisconsin
Blackhawk-Colley Road 138 kV line	Wisconsin	Goodings Grove-Lockport 345 kV line	Illinois
Rock River-Liberty 138 kV line	Wisconsin	Itasca-Tonne move Transformer	Illinois
Paddock 345/138 kV Transformer	Wisconsin	Plains 345/138 kV Transformer	Michigan
Sand Lake-Port Edwards 138 kV line	Wisconsin		

The most prominent western interface limitations include the King – Eau Claire - Arpin 345 kV facility and the 161 kV system in the Eau Claire and La Crosse areas. Because the King – Eau Claire - Arpin 345 kV transmission line is the only high voltage facility within the western interface, it quickly reaches its capability. Since there are no other high voltage facilities within the western interface, the loss of this single facility results in the overload of several other lower voltage transmission elements and severely compromises system security and integrity.

The most prominent southern interface limitation is the Electric Junction – Plano Red 345 kV facility. This facility limits import capability for the loss of the Electric Junction – Plano Blue 345 kV transmission line. A southern interface facility, the Electric Junction – Plano 345 kV Red and Blue circuits surfaces as a limitation for western interface imports because of a phenomenon known as parallel path flow (sometimes referred to as loop flow). Parallel path flow occurs as a result of the Laws of Physics that govern the inter-relationship between voltage, current, and resistance. Because the western interface consists of a single 345 kV line, which is relatively weak (i.e. high impedance), a certain portion of an import by

Wisconsin from the west will actually flow on the southern interface. Power flow studies confirm that approximately 50% of an import from the west will flow into Wisconsin over the southern interface facilities. This large amount of parallel path flow is yet another indication of the weak interconnection between Wisconsin and eastern Minnesota and underscores the need to reinforce the western interface.

In many instances, additional facilities were added to create a variation of an original reinforcement option considered by the WIREs group. This process ultimately lead to the development of forty-seven reinforcement options. A complete description of each of the forty-seven reinforcement options is contained in Appendix C of the WIREs Phase I Study Report; the detailed power transfer capability study results for each reinforcement option is contained in Appendix E of the WIREs Phase I Study Report.

"Short List" Reinforcement Options

Those reinforcement options that did not yield transfer capabilities approaching the 2k/2k/3k objective were eliminated from further consideration. Of the remaining options, a subset of twelve was selected for further analysis and dubbed the "short list". The twelve representative plans on the short list were further analyzed to determine their impact on the Arpin phase angle separation problem and on system losses[5]. In addition, indicative capital cost estimates were prepared for each plan[6]. Tabular study results of the twelve reinforcement options and a complete listing of the projects required within each plan are included in Appendix D of the WIREs Phase I Study Report.

The following table summarizes the major facilities that constitute each representative plan and lists the attributes of each plan.

[5] The Phase II WIRE study considered the change in generation at Weston 3 (delta-P analysis) which is a direct measurement of the system limitation for which the Arpin phase angle is a proxy. The Phase II delta-P analysis supersedes the Arpin phase angle results of Phase I. In addition, the Phase II study conducted a full economic analysis of each reinforcement option's impact on system losses.

[6] The Phase II WIRE study developed full construction cost estimates for each reinforcement plan which supersede the Phase I indicative cost estimates.

Table 2 Short List Summary Results

Plan	Major Facilities	Western Interface Import FCTTC[1] (MW)	Southern Interface Import FCTTC[1] (MW)	Indicative Capital Cost[3] (M)	Arpin Phase Angle[4] (deg)	System Loss Savings[2] (MW)
1c	Salem - Fitchburg 345 kV N Madison – Fitchburg – Rockdale 345 kV Plano - Plano Tap red and blue 345 kV	2220	2040	$122	92	97
2e	Prairie Island – LaCrosse - Columbia 345 kV Plano - Plano Tap red and blue 345 kV line	2120	2150	$138	78	108
2f	Salem-Paddock 345 kV line Plano-Plano Tap red and blue 345 kV line	1980	1960	$93	95	79
3e	Arrowhead-Weston 345 kV Weston-South Fond du Lac 345 kV South Fond du Lac-Plano 345 kV	2160	2020	$181	65	131
3j	Arrowhead-Weston 345 kV Plano-Plano Tap red and blue 345 kV line	2260	2100	$139	70	139
3k	Arrowhead-Weston 230 kV Plano-Plano Tap red and blue 345 kV line	2160	2010	$118	83	113
5a	Chisago - Apple River – Weston 345 kV Eliminate need for Chisago - Apple R 230kV Plano-Plano Tap red and blue 345 kV line	2280	2130	$149	48	134
6c	Chisago - Rocky Run 500 kV Rocky Run - S. Fond du Lac 345 kV Plano-Plano Tap red and blue 345 kV line	2320	2160	$212	38	173
8b	Wilmarth - Byron – Columbia 345 kV Plano-Plano Tap red and blue 345 kV line	2090	1970	$143	80	102
9a	Huron - Split Rck – Lakefield Jnc 345 kV Lakefield Jnc – Adams 345 kV Adams - Genoa – Columbia 345 kV Plano-Plano Tap red and blue 345 kV line	2570	1960	$263	72	143
12	Plano-Plano Tap red and blue 345 kV line	1910	1850	$58	98	73
13c	Arrowhead – Plains 345 kV Morgan - N Appleton 345 kV Plano-Plano Tap red and blue 345 kV line	2250	2070	$165	77	124

Table Notes:
1. 1000 MW simultaneous import bias on the opposite interface
2. Loss savings relative to the base case (1000 MW simultaneous import on each interface)
3. 1998 $
4. Arpin phase angle measured at Arpin with the Eau Claire – Arpin 345 kV line open and a simultaneous import of 3000 MW (2000 west, 1000 south).

Table 2 shows that the twelve representative reinforcement plans all achieve or nearly achieve a non-simultaneous import capability of 2000 MW on each interface and a 3000 MW simultaneous import capability into eastern Wisconsin. The table and Appendix D of the WIREs Phase I study results also demonstrate that many projects are common to nearly all of the reinforcement alternatives.

The common sets of projects are characterized in two distinct groups: Wisconsin projects and northern Illinois projects. The Wisconsin projects include upgrades to existing equipment in the Eau Claire area and the conversion of the Oak Creek - Arcadian 230 kV line to 345 kV. The capital cost of the Wisconsin projects is approximately $18 million. The northern Illinois upgrade projects include breaker, terminal, and line conductor upgrades in the northern portion of the ComEd system. The capital cost of the upgrade projects in northern Illinois is approximately $3 million.

Also common to most of the short list alternatives is the Plano - Plano Tap red and blue 345 kV line. This twenty mile double-circuit 345 kV line is required to relieve first-contingency overloads of 345 kV circuits north of the Plano substation and is required for every reinforcement alternative except Plan 3e which includes a 345 kV line from the South Fond du Lac substation to the Plano substation. The Plano Tap station is located on the Lockport - Lombard red and blue 345 kV line which is a new facility that ComEd anticipates to be in service by 2001 and is included in the 2002 base case. Without the Lockport - Lombard red and blue 345 kV facility addition, other reinforcements in the northern Illinois area would be required to reach the FCTTC levels in Table 2. The capital cost of the Plano - Plano Tap red and blue 345 kV line is approximately $35 million. Although not required for local load serving until the 2004 or 2005 time frame, a subsequent analysis demonstrated that an interim reconfiguration of the Plano 345 kV substation (the opening of a 345 kV bus tie breaker) will delay the need for the Plano – Plano Tap 345 kV facility in order to achieve the 2k/2k/3k objective.

Table 2 includes a tabulation of the Arpin phase angle separation upon the loss of the Eau Claire – Arpin 345 kV facility while importing a total of 3000 MW. Although indicative of the overall system strength, the Arpin phase angle limitation of 60 degrees is no longer an appropriate proxy for the maximum instantaneous power output change at Weston upon closure of the Eau Claire – Arpin 345 kV line. The addition of a major transmission line across the western interface changes the system characteristics such that a direct measurement of the power change at Weston is required to determine whether or not the system is limited at the maximum import capability of 3000 MW. The Phase II WIRE study considered the direct measurement of the instantaneous power change (delta-P) at Weston. However, the Arpin phase angle does give an indication of the relative performance of each option with respect to system strength. A lower phase angle indicates less “separation” and hence a stronger system. Table 2 demonstrates that reinforcement options which parallel the existing King – Eau Claire – Arpin 345 kV facility and terminate in central Wisconsin have relatively lower Arpin phase angles.

Plan 12 consists of the Wisconsin upgrade projects, the northern Illinois upgrade projects and the Plano - Plano Tap red and blue 345 kV line. Alternative 12 nearly provides the transfer capability objective of this study but does not perform well when the Arpin phase angle and system loss savings are considered. Plan 12 has the highest Arpin phase angle at 98 degrees and, because Plan 12 does not establish a new high voltage tie across the western interface, will not eliminate the need for an Arpin flow limit which will severely limit transfer capability. If the 775 MW flow limit is enforced, the western interface FCTTC of Plan 12 is 1120 MW or only 310 MW more than the base case FCTTC. Despite its performance deficiencies, Plan 12 is included in the short list to demonstrate how the addition of facilities to those included in Plan 12 increase the FCTTC, reduce the Arpin phase angle and increase loss savings. Plan 12 also illustrates the significant contribution of the ComEd area reinforcements toward satisfying the goal of increasing transfer capability.

Table 2 also demonstrates that relative to the base case, each reinforcement alternative produces significant loss savings on the system. Those projects with higher indicative cost estimates usually contain more facilities and higher-voltage facilities that result in greater loss savings. Although not accounted for in the cost estimates, evaluation of loss savings is of economic significance because the capacity (MW) and energy (MWh) which losses consume must be supplied from the power system's generation resources[7]. The loss savings differential between the alternative with the largest loss saving (Plan 6c) and the alternative with the smallest loss savings (Plan 12) is 100 MW. The Phase I WIRE study did not attempt to fully define the value of loss savings due to the time constraints imposed upon this study effort. However, previous interface expansion and local load serving studies have credited loss savings with a 20 - 35 year cumulative present worth of $1 to $4 per watt although a range of $1.3 to $2.8 is likely more reasonable given the uncertainty associated with loss valuation. Given the $1.3 to $2.8 per watt value, a 100 MW loss differential equates to a present worth savings of $130 million to $280 million.

Direct Current (DC) Transmission Options Considered

Given the scope of transmission reinforcements identified in the Phase I WIRE study, several direct current transmission options were contemplated. However, a point-to-point DC express line from Manitoba or western MAPP to eastern Wisconsin provides little or no improvement in the system performance of the western interface when compared to AC alternatives and is electrically equivalent to installing a generator inside Wisconsin. An AC transmission reinforcement designed to increase transfer capability across the western interface has several advantages over a point-to-point DC transmission line:

1. Unlike DC transmission lines, high-voltage AC transmission lines are easily “tapped” to provided critical local load serving support.
2. A DC transmission line between western MAPP and eastern Wisconsin would cost on the order of $650 million compared to the AC transmission reinforcements which are estimated to cost between $200 and $300 million. At approximately $250,000/MW, the AC/DC converter stations that are required at each end of the line are nearly $250 million alone for a line capable of transferring 1000 MW.
3. Additional stability problems can occur when DC transmission facilities are connected in parallel with an AC system.
4. Inlet and outlet constraints at each terminus of a DC line often limit the ability to fully recognize the capacity of DC transmission without substantial improvements to the AC power system. This means that additional transmission lines, most likely 345 kV transmission lines, are required to

[7] The Phase II study conducted a full economic analysis of each reinforcement option’s impact on system losses.

supply power to the sending end and distribute power from the receiving end of the DC transmission line.

5. The high capital cost of DC transmission often requires a long-term firm power sale to be financially viable.

   The Phase I WIRE study also evaluated a point-to-point DC express line between the eastern and western shores of Lake Michigan. The evaluation demonstrated that a DC line between the Cook substation in southwestern Michigan and the Zion substation in northeastern Illinois is effective in eliminating the need for the ComEd area reinforcements common to several of the plans. The evaluation also showed that the benefit of an underwater DC tie declines as the termination point moves north into Wisconsin. The cost of the underwater DC line however, is approximately $200 million or about five times more expensive than the estimated $38 million northern Illinois reinforcements.

Phase I Conclusions and Recommendations

Phase 1 of the WIRE study consists of a screening analysis of alternatives for increasing transfer capability into the eastern Wisconsin region. Since this analysis primarily considers thermal limitations to transfer capability, conclusions based on this limited-scope analysis must be considered preliminary–subject to the results of more-detailed steady-state and dynamic power system studies. With this caveat, the following preliminary conclusions and observations can be drawn based on studies to-date.

1. Local load serving facilities provide 1800 - 2000 MW simultaneous import capability.
2. Local load serving facilities alone will not eliminate need for operating guides.
3. $21 million in upgrades and $35 million in new construction are required to remove thermal limitations.
4. Removal of thermal limitations does not eliminate Arpin phase angle problem.
5. $150 - $250 million of high-voltage transmission construction is required to obtain 3000 MW of simultaneous import capability.
6. Transmission construction within Wisconsin alone will not provide the target import capability.
7. Direct Current (DC) transmission provides no incremental benefit above AC options.

Based on these conclusions and observations, the WIRE study group made the following recommendations:

1. Perform additional study work.
2. Optimize regional expansion plans.
3. Perform a resource adequacy study.
4. Continue regional reliability forums.

3.4.2 WIREs Phase II Study Effort

Study Methodology

The objectives of the WIRE Phase II study effort were to refine the study results of the Phase I screening analysis by defining relative performance differences between alternative transmission reinforcement plans. Multiple evaluation techniques were utilized to establish performance profiles for each reinforcement alternative. The evaluation techniques included:

- Detailed power flow simulations
- Generator response to transmission line switching operations (a direct measurement of the Arpin phase angle problem)
- Dynamic stability
- Voltage stability
- Impact on the MAPP transmission system
- Construction cost estimates
- Impact on system losses
- Evaluated cost proxy

As with the Phase I study effort, a 2002 power flow model was utilized to perform the Phase II analysis. A complete discussion of each of the evaluation techniques is included in the WIREs Phase II study report entitled, *WIREs Phase II – A Report to the Wisconsin Reliability Assessment Organization (WRAO).*

Prior to undertaking each of these detailed transmission-planning analyses, the set of twelve representation reinforcement alternatives identified in the Phase I study were formulated into seven complete reinforcement plans. The seven reinforcement plans were developed by comparing the relative transfer capability, construction cost, loss savings, and Arpin phase angle of the original twelve options. The ability to eliminate existing operating guides that are required to maintain security of the bulk system but degrade local load serving capability was also considered.

In addition, three new reinforcement plans were developed based on the options evaluated in the Phase I process. Plan 9b (Lakefield Jnc – Adams – Genoa – Columbia 345 kV) is a trimmed version of the Phase I Option 9a and is less costly from a construction cost standpoint. Plan 5b (Apple River – Weston 230 kV) was added to consider dynamic and voltage stability performance of a lower voltage version of Plan 5a. Plan 10 (King – Weston 345 kV) was added because of the potential dynamic stability differences between it and Plan 5a (Chisago – Weston 345 kV). The group discussed the King – Weston reinforcement in the Phase I process but noted that from a thermal standpoint, it is electrically similar to Plan 5a. However, potential dynamic and voltage stability differences prompted the group to add Plan 10 to the Phase II process.

The major transmission system additions associated with each of the seven reinforcement plans evaluated in the Phase II study are:

- Plan 1c (Salem – Fitchburg 345 kV)
- Plan 2e (Prairie Island – Columbia 345 kV)
- Plan 3j (Arrowhead – Weston 345 kV)
- Plan 5a (Chisago – Weston 345 kV)
- Plan 5b (Apple River – Weston 230 kV)
- Plan 9b (Lakefield – Columbia 345 kV)
- Plan 10 (King – Weston 345 kV)

Performance Evaluation

All of the study results discussed below are summarized in Table 3 found on page 34.

Detailed Power Flow Simulations

Several detailed power flow simulations were performed on each reinforcement plan to determine:

- the reactive voltage support required to achieve the 3000 MW simultaneous import capability
- the maximum transfer capability
- the sensitivity of the 3000 MW import capability to modeling assumptions

The detailed power flow simulations verify that each of the reinforcement plans is capable of supporting 3000 MW of simultaneous import capability. However, some plans provide more incremental transfer capability above the 3000 MW target than others do. In addition, the maximum transfer capability of some plans is more sensitive to changes in modeling assumptions than others. Table 3 (rows a-d) summarizes the power flow simulation results and shows the maximum transfer capability of each reinforcement plan under different modeling assumptions.

Generator Response to Transmission Line Switching Operations

The ability to transfer power across the western interface is currently limited by the Arpin phase angle. The Arpin phase angle limitation is a proxy for the maximum amount of stress introduced to the Weston generators when any portion of the King – Eau Claire – Arpin 345 kV line is switched. A sudden loss of any portion of the King – Eau Claire – Arpin 345 kV line results in a system "separation" between MAPP and eastern Wisconsin. When the line is re-closed across this "separation" an instantaneous change in power output is experienced on the Weston generator units, which places mechanical stress on the shaft of each unit. The Weston units experience this phenomena due to their physical proximity to the western interface. The current Arpin phase angle limitation is 60 degrees (the maximum "separation").

Rather than focus on the Arpin phase angle as a proxy measurement for the impact on the Weston generating units, the WIREs group focused on a direct measurement; the instantaneous change in power output of the Weston units upon the closure of the Eau Claire – Arpin 345 kV line. Analysis of the present day system calculated the Weston "delta P" corresponding to the re-close of the Eau Claire - Arpin 345 kV line with a phase angle difference of 60 degrees demonstrated that Weston Unit #3 would experience a “delta P” of 37.2% (or 0.372 per unit).

Analysis of each of the seven reinforcement plans at the target simultaneous transfer capability of 3000 MW (2000 MW west/1000MW south) indicates that each plan except for Plan 1c (Salem – Fitchburg 345 kV) results in a “delta-P” less than the 37.2% limit. The Weston “delta-P” results for each of the seven reinforcement plans are shown in Table 3 (row e)

<u>Dynamic Stability</u>

Dynamic stability is the measure of the system’s ability to react to a major system disturbance such as a short circuit on a transmission line, the opening of a line, the loss of a large generator, or the switching of a major load. Dynamic stability evaluates the ability of the system’s generation units to remain synchronized and to “recover” from a system disturbance.

The dynamic stability analyses performed in this study considered the following:

1. WUMS and MAPP area disturbances
2. New facility disturbances
3. Maximum Columbia & Weston generation output sensitivities
4. Breaker failure performance (Rocky Run area)
5. Damping of the ¼ Hertz mode of oscillation
6. Incremental transfer capability assessment based on ¼ Hertz mode of oscillation.
7. Dynamic reactive support requirements

In general, all plans met established transient voltage and rotor angle criteria for the WUMS 2000 MW west – 1000 MW south import transfer condition. No additional reactive voltage support (VAr) requirements, over and above those identified through the power flow analyses, were identified.

The most pronounced difference between the reinforcement plans was observed for disturbances involving a loss of a major Twin Cities 345 kV outlet facility. For a loss of either the King – Eau Claire – Arpin 345 kV or the Prairie Island – Byron 345 kV transmission line, differences in transient voltage performance within MAPP and WUMS and damping of the MAPP/MAIN ¼ Hertz mode of oscillation were observed. Damping of the ¼ Hertz mode of oscillation is currently a stability limiting condition for the Twin Cities export (TCEX) limitation.

The damping of the ¼ Hertz (Hz) oscillation mode is dependent on transfer levels. To determine the maximum transfer capability, at which the ¼ HZ mode is a limit, an incremental transfer capability (ITC) number was calculated based on the loss of either the King or Prairie Island 345 kV lines. The incremental transfer capability is the additional amount of transfer capability beyond the 2000 MW target the system is capable of supporting before reaching a stability limitation. The dynamic stability results of the ¼ Hz mode of oscillation are shown in Table 3 (row f).

Some generator stability problems were identified in the Rocky Run area for delayed clearing breaker failure cases studied with maximum generation at the Weston generating plant. These were found to be problems inherent in the base case and can be corrected with reduced failed breaker clearing times.

Voltage Stability

Voltage stability is the measure of a system's ability to maintain adequate voltage profiles following a major system disturbance such as the loss of a critical transmission line. Without adequate voltage support, a system could experience "voltage collapse"; a condition characterized by declining voltages that cannot support customer load. The results of this analysis show that voltage instability is not encountered at a western interface transfer of 2000 MW.

The WIREs group undertook the voltage stability assessment with the MAPP Transmission Reliability Assessment Working Group and Power Technologies Inc. (PTI), a power system study consultant. The consultant's study work focused on western interface transfers because the western interface is more susceptible to voltage collapse than the southern interface. Past operating experience indicates that the southern interface is limited by thermal overload constraints rather than by voltage stability concerns.

The consultant utilized conventional power flow and optimum power flow techniques to establish voltage limitations at various power transfers.

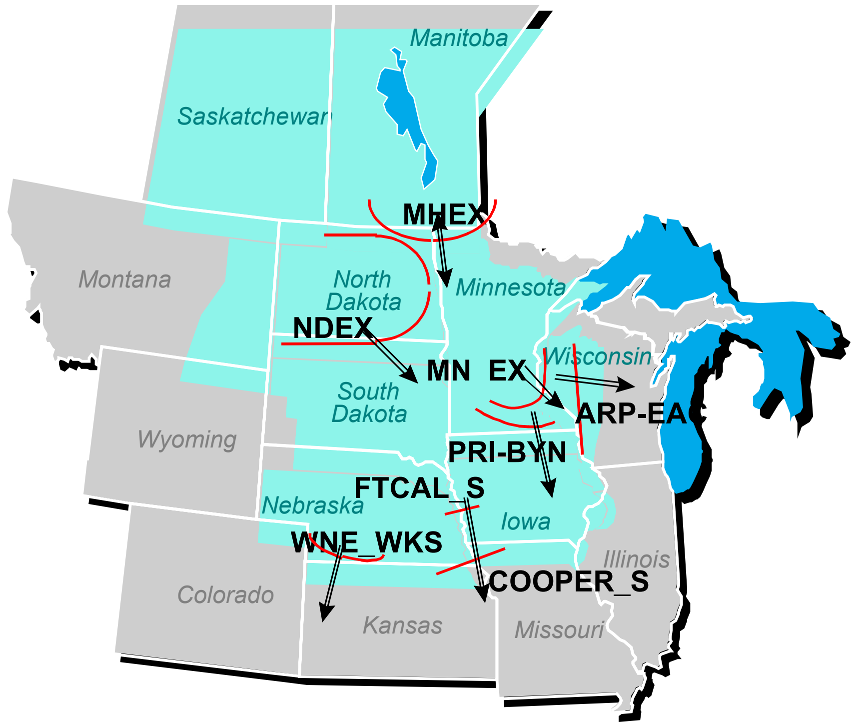
In order to determine the maximum western interface transfer at which voltage instability is encountered, transfers were increased beyond the 2000 MW level (all other limitations were ignored). Results of this sensitivity are shown in Table 3 (row g) and demonstrate that some reinforcement plans provide more western interface transfer capability before voltage instability is exhibited.

Impact on the MAPP Transmission System

The impact of the seven reinforcement plans on the neighboring MAPP system was evaluated by considering the change in flow on the MAPP flowgates. Flowgates are a set of transmission lines with a single flow capability that define a thermal, voltage, or stability limitation. The geographical areas represented by the MAPP flowgates are shown in Figure 9 below.

The change in flow on each flowgate due to the addition of a reinforcement plan to the system was determined by measuring the before and after reinforcement flow at a transfer level of 3000 MW (2000 MW western transfer / 1000 MW southern transfer). These results demonstrate that most reinforcement plans reduce flow on the MAPP flowgates as they are defined today. The results are shown in Table 3 (rows h-l).

Figure 9 MAPP Flowgate Definitions



Impact of System Losses

An analysis was undertaken to quantify the relative cost of system losses among the reinforcement plans. The costs associated with losses are summarized as an equivalent capital investment adjustment to the initial capital construction cost for each alternative. An equivalent capital cost adder is calculated for each reinforcement plan that is relative to the plan with the least losses. The capital cost adder for each reinforcement plan is shown in Table 3 (row m).

The process computes the lifetime costs for the installed generating capacity and associated energy to serve the losses that would prevail for each alternative. Transmission losses are included for the MAPP, MAIN, and SPP Regions. The cost adder is based on subtracting the life time costs of the lowest cost alternative, from the cost of all alternatives. Three components of adjusted capital cost were computed. These are due to generation capacity to supply the losses, annual energy losses to serve load, and annual energy losses due to point-to-point transactions.

Capacity Cost

Each plan causes the greatest demand for losses at some anticipated transfer level condition. In the cost evaluation, the maximum amount of loss caused by a plan is assigned a cost of 400 $/kW. The resulting cost represents the cost for installed generating capacity that would be required to serve the losses.

Energy Loss for Load
Each plan has energy losses associated with the annual hourly loss that occurs as the load pattern is served. An annual load pattern is sufficiently predictable, so that the resulting cost for Energy Loss for Load is a constant for each plan. The annual energy to serve load in each plan has been set at 30 % of the energy that would be lost if the peak load occurred all hours in the year. The annual energy lost as a consequence of serving load is priced out at 15 $/MWh. The resulting annual energy cost is equated to a levelized annual carrying charge. The annual carrying charge dollars are then converted to an equivalent capital investment, by dividing by 15 %.

Energy Loss for Transactions
Each plan has energy losses that are required to support the various point-to-point transactions that are planned. After determining the annual energy associated with the point-to-point transactions, a capital investment is computed by dividing by 15 %. Due to the varying degrees that future point-to point usage can occur, the annual Energy Loss for Transactions have been computed over a range of operating conditions. For example 5% of the time a 2000 MW import into WUMS from the West and a 1000 MW import from the South is one operating point along with, 40% of the time at a 1000 MW West import and 0 MW South import, etc.

<u>Construction Cost Estimates</u>

The cost estimates for the WIREs reinforcement plans are comprised of three parts. These three parts are cost of transmission lines, cost of substation terminal additions, and the cost of associated projects. The total construction cost, expressed as a range of values for each reinforcement plan, is shown in Table 3 (rows n and o). The construction cost estimates contain a range to account for discrete “study areas” between substation end-points. The construction costs represent overnight capital costs expressed in 2002 dollars. A team of environmental analysts retained by the WRAO to examine the seven reinforcement plans developed the “study areas”.

The three segments of the construction cost estimates are discussed below.

Cost of Transmission Lines
An independent engineering consultant was retained by WRAO to develop the construction cost estimates for the transmission lines. The transmission line cost estimates were based on the study areas defined for each plan by an environmental consultant working with WRAO and the WIREs group. For each study area, a single circuit cost estimate and a cost estimate that utilized all potential double circuiting opportunities were developed. In most cases, four cost estimates were developed for each reinforcement plan (two study areas times two cost estimates).

Cost of Substation Terminal Additions
The cost estimates for the substation terminal additions and enhancements required for each WIREs plan were developed by the utilities whose service territories contained the substations under consideration. The consultant supplied standard substation "component costs" which were used by each utility in determining the estimated cost for these improvements. The component costs used are listed in Appendix C of the WIRE Study Phase II Report.

Cost of Associated Projects
The associated projects are various system improvements that were required enhancements in order for the WIREs plan under consideration to achieve the stated power transfer goals. The cost estimates for these projects were developed by the utilities whose service territories contained the system elements under consideration.

<u>Evaluated Cost Proxy</u>
An evaluated cost proxy, which merged the construction cost, the equivalent capital cost adder for losses, and other savings from avoided local load serving projects is included in Table 3 (row p and q). The evaluated cost proxy is a portrayal of the overall economic impact of each reinforcement plan based on construction cost, the cost of losses, and a credit for avoided facilities. As with the construction cost estimates, the evaluated cost proxy is shown in 2002 dollars as a range of overnight capital costs to account for the different "study areas" for each reinforcement plan (the "study areas" were developed by the WRAO's environmental team).

Table 3 Phase II Performance Summary

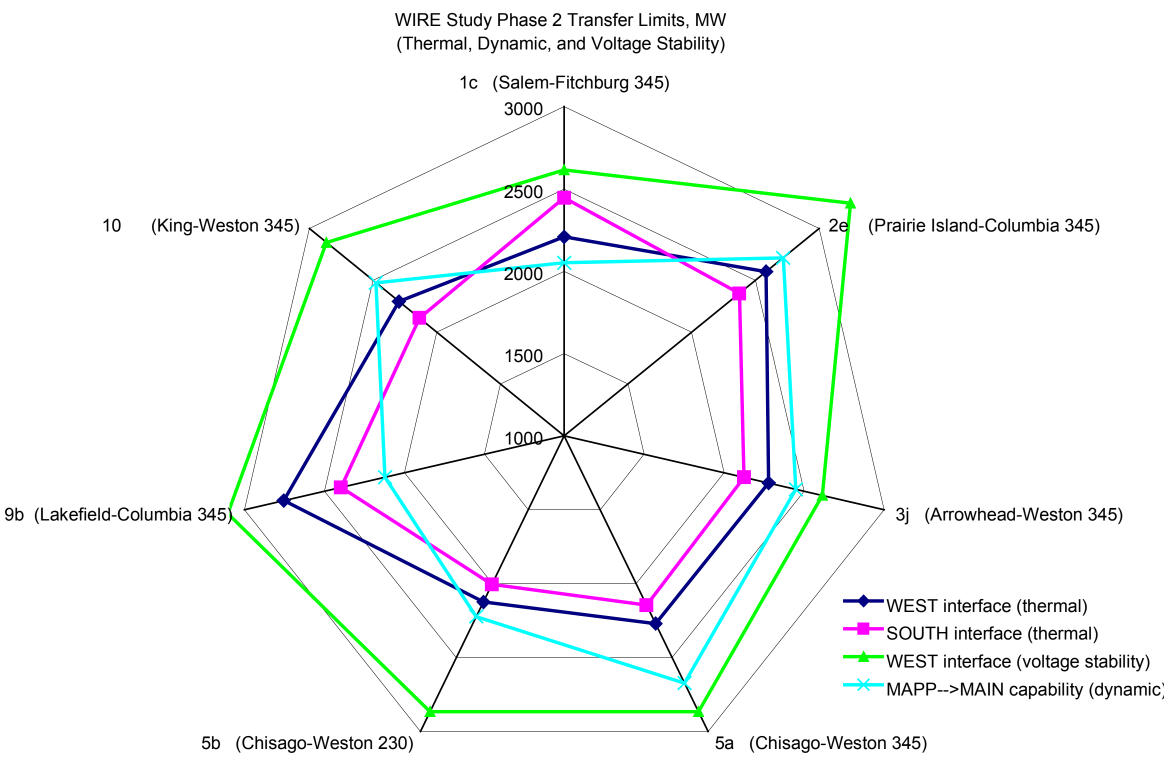
	WIREs Phase II Performance Summary All Reinforcement Alternatives Satisfy 3000 MW Simultaneous Import Objective *ver3- 4/9/99*	Salem-Fitchburg 345 kV 1C	Prairie Island-Columbia 345 kV 2E	Arrowhead-Weston 345 kV 3J	Chisago-Weston 345 kV 5A	Apple River-Weston 230 kV 5B	Lakefield Jct-Columbia 345 kV 9B	King-Weston 345 kV 10
	Southern Interface Transfer Capability (with 1000 MW western bias)							
a	Transfer Capability – Southern Interface	2450	2370	2130	2150	2010	2400	2140
	Western Interface Transfer Capability (with 1000 MW southern bias)							
b	Transfer Capability – Western Interface (MW)	2210	2580	2280	2270	2120	2750	2300
c	Transfer Capability – Source Sensitivity (MW)	2110	2550	2190	2190	2140	2810	2200
d	Transfer Capability – Sink Sensitivity (MW)	2160	2720	1860	1880	2160	2590	1890
e	Weston Delta P (per unit improvement from existing limit @ 2000 MW)	-0.013	0.015	0.036	0.166	0.064	0.009	0.247
f	Dynamic Stability - .25 Hz Damping (MW incremental xfer through WUMS)	50	720	450	670	220	120	480
g	Voltage Stability (western transfer level MW – no southern import)	2615	3245	2615	2865	2865	3105	2865
	Other Factors							
h	MAPP OPPD Flowgate Loading (avg % loading change from base case)	-1.2%	-9.3%	-7.9%	-8.6%	-5.5%	-12.4%	-7.9%
I	MAPP COOPER_S Flowgate Loading (% loading change from base case)	-7.9%	-18.1%	-14.7%	-16.1%	-11.6%	-22.3%	-15.4%
j	MAPP ECL-ARP Flowgate Loading (% loading change from base case)	-0.8%	-6.3%	-19.7%	-24.3%	-10.6%	-7.5%	-20.2%
k	MAPP PRI-BYR Flowgate Loading (% loading change from base case)	1.3%	-26.1%	-15.5%	-18.3%	-9.0%	7.0%	-16.5%
l	MAPP MN EX Flowage Loading (% loading change from base case)	0.3%	-17.6%	-17.0%	-20.6%	-6.7%	8.1%	-20.2%
	Economic Factors							
m	Losses (Capital Cost Adder w/r to Plan 3j – million $)	$50.2	$27.2	$0.0	$1.4	$38.7	$29.0	$20.8
n	Construction Cost Range (single ckt – million $)	$116 - $145	$169 - $176	$177 - $210	$172 - $205	$118 - $144	$227	$136 - $139
o	Construction Cost Range (double ckt – million $)	$158 - $227	$243 - $265	$266 - $310	$240 - $284	$171 - $208	$395	$210 - $262
p	Evaluated Cost Proxy Range (single ckt – million $)	$166 - $195	$195 - $202	$177 - $199	$126 - $149	$157 - $173	$256	$157 - $160
q	Evaluated Cost Proxy Range (double ckt – million $)	$208 - $277	$269 - $291	$266 - $299	$194 - $228	$210 - $237	$424	$231 - $283

Summary of Technical Study Results

The evaluation techniques utilized in the Phase II WIRE study demonstrate that each reinforcement plan, with the exception of Plan 1c, is capable of supporting a simultaneous transfer of 3000 MW over the western and southern interfaces into Wisconsin. The Weston delta-P performance of Plan 1c (Salem – Fitchburg 345 kV) is slightly less than criteria which indicates that Plan 1c could not sustain a simultaneous import of 3000 MW without adding additional facilities to the plan. In addition, Plan 1c did not exhibit robust damping of the ¼ Hertz inter-area oscillation when compared to the other reinforcement plans. With the exception of Plan 1c, the detailed technical analyses did not identify any "fatal flaws" that exclude any of the remaining reinforcement plans from further consideration.

Each of the evaluation techniques considered in this study were considered in isolation. In other words, the voltage stability transfer capability did not consider thermal limitations and vice-versa. The absolute transfer capability of each reinforcement plan is a function of all potential limitations including thermal, voltage, dynamic stability, and Weston delta-P. The following "radar-plot" attempts to capture how a different type of system limitation limits the transfer capability of each reinforcement plan. The most limiting factor for Plan 3j, for example, is a thermal constraint on the southern interface. This is followed by a thermal limitation of the western interface.

Figure 10 Summary of Technical Study Results



3.5 WRAO Evaluation and Recommendation

3.5.1 Introduction

Having completed the WIRE Phase I and II technical analysis and a high level environmental review of the seven reinforcement plans studied in Phase II, the WRAO undertook a quantitative and qualitative assessment of the relative performance of each of the seven reinforcement plans[8]. The WRAO utilized several factors to distinguish the relative performance of each reinforcement plan. Those factors included:

1. Interface improvement
2. Environmental and social impact
3. Construction cost
4. System losses
5. Geographical diversity

Based on an assessment of the relative performance of each plan for each of the five factors, the WRAO concluded that Plan 3j (Arrowhead – Weston 345 kV) is the best reinforcement alternative to restore reliability margins in the bulk power transmission system.

The issue of geographical diversity received special attention from the WRAO when evaluating the relative performance of the reinforcement plans. Of primary concern is the ability of a reinforcement plan to restore the reliability benefits of the interconnected transmission grid and provide access to diverse resources. Common-mode failure of multiple transmission elements is of highest concern with Wisconsin's western interface because it is currently comprised of a single 345 kV transmission line. As demonstrated, the loss of this interconnection leads to system separation, requires the implementation of operating guides to remove overloads on lower voltage facilities, and eliminates the ability to access external resources in times of generation resource deficiencies. In order to significantly improve the reliability of the transmission system and access to diverse generation resources, a second 345 kV facility which interconnects Wisconsin to the west should avoid the potential for the common-mode failure of both facilities. Common-mode failures include such events as severe thunderstorms, ice storms, and tornadoes. Attachment D of the WRAO's report on Transmission System Reinforcement in Wisconsin demonstrates that single events such as severe thunderstorms can affect multiple transmission elements that are in the same

[8] The WRAO recognizes that Plan 1c (Salem - Fitchburg 345 kV) did not meet all of the criteria established by the WIRE study team. Plan 1c (Salem - Fitchburg 345 kV) did not quite meet the criteria established for the Weston delta-P value that is a measure of the current "Arpin phase angle" problem. In addition, Plan 1c (Salem - Fitchburg 345 kV) did not exhibit robust dynamic stability performance with respect to the ¼ Hz. inter-area oscillation which causes the MAIN and MAPP system to "swing" against the remainder of the eastern interconnection. However, Plan 1c (Salem - Fitchburg 345 kV) is carried through the comparison process to demonstrate the differences between it and the remaining six plans.

geographical location. In addition, the North American Electric Reliability Council (NERC) recognized the potential for common-mode failure of multiple transmission elements to reduce reliability of the interconnected system. NERC states in their 1997 Planning Standards document:

> *The interconnected transmission systems should be planned to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.* (p.12)
>
> *Extreme contingency evaluations should be conducted to measure the robustness of the interconnected transmission systems and to maintain a state of preparedness to deal effectively with such events. Although it is not practical (and in some cases not possible) to construct a system to withstand all possible extreme contingencies without cascading, it is desirable to control or limit the scope of such cascading or system instability events and the significant economic and social impacts that can result.* (p.12)

3.5.2 Justification of Recommendation

The five factors listed below were used in the evaluation of the relative performance of the seven plans. What follows is a description of each factor along with how the recommended plan, Plan 3j (Arrowhead - Weston 345 kV), performed under each factor.

Interface improvement

This factor considers each of the quantitative measures considered by the WIRE study group such as transfer capability, Weston delta-P performance, and dynamic and voltage stability performance.

Plan 3j (Arrowhead - Weston 345 kV) clearly met the minimum criteria established for transfer capability, dynamic and voltage stability, and the Weston delta-P criteria. While other plans contributed additional interface transfer capability above the established criteria, the WRAO found this incremental capability to be negligible and within accepted modeling tolerances. Plan 3j (Arrowhead - Weston 345 kV) demonstrated robust dynamic stability and acceptable voltage stability performance.

Environmental and social impact

This factor considers several issues related to the ability to license and construct a new high voltage transmission line. Included are measures such as line length, potential for corridor sharing, proximity to population centers, environmental and jurisdictional impact, and river crossings. The WRAO recognizes that these measures are qualitative in nature. None of the transmission plans are devoid of the potential for environmental and social impacts.

After review of the environmental study work it was the judgement of the WRAO that Plan 3j (Arrowhead - Weston 345 kV) is reasonable in line length; offers significant potential for corridor sharing; and reasonably avoids significant environmental impacts.

Construction cost

This factor is also based on the work of the WIRE study group. The WIRE study group identified a range of construction cost estimates based on the study areas determined by the environmental analysis team. The construction cost estimate ranges also considered double circuit opportunities. The WRAO recognizes that although construction cost estimates are useful when considering the relative cost of each plan, the ultimate construction cost of any system reinforcement is dependent on a number of factors including construction type, conductor size, routing (terrain differences), double circuit requirements, mitigation requirements, etc.

Plan 3j (Arrowhead - Weston 345 kV), while not having the lowest construction cost, was deemed to have reasonable costs based upon the performance under the other factors.

System losses

The WIRE study group evaluated the relative electrical loss profiles of each reinforcement plan in terms of capacity and energy. Each reinforcement plan changes the electrical characteristics of the regional transmission system differently which results in different loss profiles. The WRAO considered each reinforcement plans' ability to minimize on-peak losses and yearly energy losses.

Plan 3j (Arrowhead - Weston 345 kV) clearly was the superior plan with respect to this factor.

Geographical diversity

This factor considers the geographical separation of each reinforcement plan from the existing western interface facilities (the King – Eau Claire – Arpin 345 kV). Of primary concern to the WRAO is the ability to guard against common-mode failure of the entire interface. For example, the greater the geographical separation between major transmission facilities, the less likely it is that one single event, such as a severe thunderstorm or tornado, will result in the loss of both facilities.

In terms of geographical diversity, the WRAO considers Plan 3j (Arrowhead - Weston 345 kV) to be a superior performing plan because of its physical separation from the existing King – Eau Claire – Arpin 345 kV line.

Plan 3j (Arrowhead - Weston 345 kV) demonstrates superior loss characteristics, provides for geographical diversity, has the potential to avoid significant environmental issues and is cost competitive with the alternative plans. From a technical performance standpoint, Plan 3j (Arrowhead - Weston 345 kV) meets all of the criteria established by the WIRE study team including the Weston delta-P (the current Arpin phase angle problem), dynamic stability, and voltage stability. Plan 3j (Arrowhead - Weston 345 kV) also has the ancillary benefit of demonstrated local load serving benefits in the north-central area of Wisconsin (WPS's Upperwestern area).

Plan 3j (Arrowhead - Weston 345 kV) will provide a significant improvement to the transmission system in the MAIN and MAPP regions and provide crucial support to an interface that is limited by thermal, voltage, and dynamic stability constraints. Relative to the other reinforcement plans considered, Plan 3j (Arrowhead - Weston 345 kV) is robust, minimizes environmental concerns, minimizes system losses, and provides for exceptional geographical diversity. For these reasons, the WRAO recommends that the transmission reinforcements within Plan 3j (Arrowhead - Weston 345 kV) are in the best interest of regional reliability and transmission interface expansion.

3.6 Transfer Capability Requirements

As previously discussed, the bulk power transmission system provides access to external generation resources in times of generation deficiencies and emergency operating situations. The ability to access external resources allows an electric utility to reduce its installed generation capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. Wisconsin utilities, for example, maintain a generation reserve margin of 18%, meaning their installed generation capacity is 118% of the forecasted peak load. However, the 18% reserve margin does not ensure uninterrupted electric service under various operating conditions. Only with access to generation resources external to Wisconsin via the bulk power transmission system can reliability of service be maintained. Without transmission interconnections, Wisconsin electric utilities would need to maintain a generation reserve margin of approximately 30% to maintain reliability.

The access to external generation resources via transmission interconnections is an issue fundamental to the welfare of the entire electric production and delivery system within North America. The North American Electric Reliability Council (NERC) acknowledged this issue when developing guidelines on how to calculate the availability of transmission transfer capability available to third parties for commercial purposes. The NERC determined that a certain amount of available transfer capability known as capacity benefit margin, or CBM, should be preserved to maintain the reliability of electric supply. As a reliability component, CBM is withheld from the market place on a firm basis and preserved for load serving entities for use during emergency generation deficiencies.

The reliability of an electric system is measured with a probabilistic analysis known as a loss of load expectation study or LOLE. A LOLE study is a measure (in days per year) of the probability that system demand (load) will exceed the supply (generation). The methodology incorporates probabilistic information regarding the forced outage rate and availability of generation units and uncertainty related to load forecasts. The industry standard for reliability is an LOLE of 0.1 days per year or 1 day per 10 years. The 0.1 days/year criterion is used for planning purposes to ensure that the supply of electricity exceeds customer demand for a variety of operating conditions.

3.6.1 WRAO LOLE Analysis

The WRAO, in their Report of the Wisconsin Reliability Assessment Organization on Transmission System Reinforcement in Wisconsin, conducted an LOLE analysis focused on determining the amount of transmission transfer capability into eastern Wisconsin needed to achieve the 0.1 days/year criterion given certain assumptions regarding new generation capacity installed within eastern Wisconsin. Given the uncertainty associated with new generation capacity, the WRAO conducted two LOLE simulations to determine the upper and lower bounds of transmission transfer capability required to maintain the 0.1 day/year criterion. The WRAO concluded that under normal contingency situations, the minimum transfer capability required by eastern Wisconsin to maintain reliability through 2007 is expected to range from 1000 MW to as much as 3400 MW. Based on these calculations and a number of qualitative requirements for additional transfer capability such as parallel path flow, diversity of supply, unhindered access to external generation markets, and operating flexibility, the WRAO recommended expansion of the transmission system to support a simultaneous import of 3000 MW. A complete narrative of the WRAO's LOLE analysis and a discussion of numerous qualitative requirements for additional transfer capability are found in Appendix C of the WRAO's report.

The WRAO LOLE simulations, however, did not consider the variability associated with the determination of transmission transfer capability or the inter-relationship between generation deficiencies and transmission transfer capability. As discussed in the WIREs Phase II Report, it is not uncommon to observe a ±10% change in the calculation of transmission transfer capability based on modeling assumptions. Consideration of this transfer capability calculation bandwidth drives the WRAO's upper bound beyond the 3700 MW level. The transfer capability calculations performed by the MAIN reliability center for determining the commercial availability of the transmission system also demonstrate this variability. For example, the following table lists the recent weekly availability of transmission (shown in MW as a total transfer capability) on the MAPP – Wisconsin interface:

Table 4   MAPP-Wisconsin Weekly Firm TTC Values

MAPP – Wisconsin Weekly Firm TTC	
Date	Total Transfer Capability (MW)
8/18/99	580
8/25/99	380
9/1/99	760
9/8/99	800
9/15/99	620
9/22/99	720
9/29/99	590

This table shows that in just over a month, the transfer capability varied from a low of 380 MW to a high of 800 MW – a difference of 420 MW or over a 200% change from the 380 MW value. The variability of real time operating conditions is manifested in fluctuations of the capability of the bulk power transmission system and requires consideration when planning for expansion of the system.

Neither the WRAO LOLE analysis, nor any LOLE analysis, directly accounts for the inter-relationship between the availability of generation and transmission transfer capability. Based on probabilistic techniques, the LOLE program determines the probability of multiple generation states. The generation states include the possibility that one or more generators are completely or partially forced out of service. However, the program does not account for the possibility that a generator outage could actually reduce (or in some cases, completely drive to zero) the transmission transfer capability that is required to deliver the external resources required to maintain the 0.1 days/year criteria. This inter-relationship, which is often neglected as we move into a deregulated environment, requires consideration when planning for the expansion of the system. For example, if the LOLE results demonstrate that 3000 MW of transfer capability is required to maintain the 0.1 days/year criterion during all plausible generation outage emergencies, and the loss of a large generating unit causes a 500 MW decrease in transmission transfer capability, then 3500 MW of transfer capability is required to maintain a reliable system.

Additional changes within the LOLE input assumptions also demonstrate a need to increase Wisconsin's import capability requirements beyond the range identified by the WRAO analysis. An increase in the forced outage rate of a particular class of units or a decrease in the maximum generation capability of a unit will increase the amount of transmission transfer capability required to maintain the 0.1 day/year criterion. Although all of Wisconsin's generation plants are expected to perform adequately through their complete life cycle, it is not unreasonable to consider that as generation units age, the likelihood of reduced performance increases. The consideration of common-mode failures that disable multiple units at a single plant (such as fuel delivery and handling) effectively increases the LOLE import capability requirement. Other factors, such as higher than normal ambient air and cooling water temperatures, emissions restrictions, and more stringent air and water quality standards can decrease the availability of a generation unit and thereby increase the dependence on transmission interconnections to external resources during times of emergencies. Situations encountered during the 1999 summer demonstrated that such factors can substantially increase dependence on transmission interconnection capacity to external regions.

3.6.2 Additional LOLE Analysis

In an attempt to further define the transfer capability requirements of the interconnected transmission system, an additional LOLE analysis was conducted. The additional LOLE analysis changed some of the input assumptions made by the WRAO in their LOLE analysis. In particular, the WRAO made the assumption that the transmission transfer capability to access external resources is twice as available in the summer and winter seasons as it is in the spring and fall. This assumption was made as a proxy for the wide range of transactions made in the wholesale power market, ranging from 1 hour to several years and the variability of transmission transfer capability as a function of actual operating conditions. To test the impact of this assumption on the transmission transfer capability required to maintain the 0.1 days/year criterion, an additional LOLE analysis was conducted with the assumption that transmission transfer capability is 100% available for all hours of the year. The results of this additional analysis are included in the following two tables.

Table 5 LOLE Analysis – 18% Reserves Maintained

Generation Added to Meet 18% Reserve Margin, 100 % Available Import Capability Added to Meet LOLE Criterion (Case 1a)

Line No.		1999	2000	2001	2002	2003	2004	2005	2006	2007
1a	Net Operable Generation Capacity at the Beginning of Each Year	11,005	11,339	12,314	12,484	12,694	12,924	13,174	13,434	13,654
1b	New Approved NUG Generation Installed by 6/1 of Each Year	179	750	-	-	-	-	-	-	-
1c	New Committed Utility-Owned Generation Operable by 6/1 of Each Year	155	225	-	-	-	-	-	-	-
1d	Total Operable Generation as of 6/1 of Each Year	11,339	12,314	12,314	12,484	12,694	12,924	13,174	13,434	13,654
1e	Projected Peak Demand Net of Interruptible Loads	10,215	10,374	10,582	10,757	10,953	11,161	11,387	11,573	11,754
1f	Reserve Margin Before Other Capacity Additions	11.0%	18.7%	16.4%	16.1%	15.9%	15.8%	15.7%	16.1%	16.2%
1g	Generation Added to Meet an 18% Reserve Margin	-	-	170	210	230	250	260	220	220
1h	LOLE (days/year) Before Capacity Purchases	7.01	3.77	1.20	1.38	1.38	1.17	1.10	1.00	0.92
1I	Capacity Purchases (Import Capability) Needed to Meet 0.1 day/year LOLE	1,260	1,040	750	820	860	780	770	750	730
1j	Total Capacity (1d + 1g + 1i)	12,599	13,354	13,234	13,514	13,784	13,954	14,204	14,404	14,604
1k	Reserve Margin Required to Meet 0.1 day/year LOLE	23.3%	28.7%	25.1%	25.6%	25.8%	25.0%	24.7%	24.5%	24.2%
	Cumulative Generation Capacity Added	334	1,309	1,479	1,689	1,919	2,169	2,429	2,649	2,869

Table 6 LOLE Analysis – No Additional Eastern Wisconsin Generation Post-2000

No Generation Added Beyond 2000, 100 % Available Import Capability Added to Meet LOLE Criterion (Case 2a)

Line No.		1999	2000	2001	2002	2003	2004	2005	2006	2007
2a	Net Operable Generation Capacity at the Beginning of Each Year	11,005	11,339	12,314	12,314	12,314	12,314	12,314	12,314	12,314
2b	New Approved NUG Generation Installed by 6/1 of Each Year	179	750	-	-	-	-	-	-	-
2c	New Committed Utility-Owned Generation Operable by 6/1 of Each Year	155	225	-	-	-	-	-	-	-
2d	Total Operable Generation as of 6/1 of Each Year	11,339	12,314	12,314	12,314	12,314	12,314	12,314	12,314	12,314
2e	Projected Peak Demand Net of Interruptible Loads	10,215	10,374	10,582	10,757	10,953	11,161	11,387	11,573	11,754
2f	Reserve Margin Before Other Capacity Additions	11.0%	18.7%	16.4%	14.5%	12.4%	10.3%	8.1%	6.4%	4.8%
2g	LOLE (days/year) Before Capacity Purchases	7.01	3.77	1.74	3.20	5.56	7.73	11.85	16.34	21.99
2h	Capacity Purchases (Import Capability) Needed to Meet 0.1 day/year LOLE	1,260	1,040	890	1,150	1,430	1,570	1,810	2,000	2,200
2i	Total Capacity (2d + 2h)	12,599	13,354	13,204	13,464	13,744	13,884	14,124	14,314	14,514
2j	Reserve Margin Required to Meet 0.1 day/year LOLE	23.3%	28.7%	24.8%	25.2%	25.5%	24.4%	24.0%	23.7%	23.5%
	Cumulative Generation Capacity Added	334	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309

These tables show that the amount of transmission transfer capability required to maintain reliability through 2007 ranges from 730 MW to 2200 MW (a reduction from the WRAO's 1000 – 3400 MW range) when transmission transfer capability is assumed to be 100% available all year. As previously discussed, changes in input assumptions can lead to notable changes in the observed output of an analytical analysis. In this case, assuming that the transmission transfer capability is the same in all seasons rather than only half available in the spring and fall, leads to a reduction in the amount of transmission transfer capability required to maintain reliability. As with any input assumption however, there are impacts that are not always accounted for in the analytical process. Because the consumption of electricity in the spring and fall seasons is lower than in the summer and winter, most generation maintenance is scheduled during the spring and fall. In addition, maintenance on transmission components (such as breakers, switches, relay systems, etc.) is also scheduled during lighter load periods. As previously discussed, generation profiles and transmission system topology can significantly impact transmission transfer capability. The unavailability of generation resources and transmission components can significantly reduce transmission transfer capability and therefore the reliability benefit associated with the transmission interconnection.

The WRAO LOLE analysis and the additional LOLE studies presented here demonstrate that input assumptions can significantly impact the results in both an upward and downward direction. Because it is difficult, if not impossible, to accurately predict the future landscape of the generation and transmission marketplace, it is reasonable to assess multiple scenarios. The 3000 MW transfer capability target established by the WRAO is within the realm of reasonable scenarios used to determine future transfer capability requirements.

Beyond the LOLE import capability requirements, the existing transmission infrastructure of the western interface is in need of reinforcement. Throughout the early 1990s, Wisconsin's electric utilities undertook several projects to maximize the capability of the existing western interface infrastructure. This included the addition of capacitor banks, reconductoring of lower voltage facilities, protection system upgrades, the replacement of limiting terminal equipment, and the development of operating guides to increase capability. However, the opportunity to undertake smaller projects to increase capability has been fully exhausted. As demonstrated by the recent Transmission Assessment Reliability Studies for the 1999 summer undertaken by MAIN, the existing King – Eau Claire – Arpin 345 kV facility limited not only eastern Wisconsin's import capability from the west but the entire MAIN region's ability to import from MAPP. Operating guides that were originally developed to support inter-area transactions are now needed to support the transmission system without any transactions at all. Routine maintenance on the King – Eau Claire – Arpin – Rocky Run 345 kV is difficult, and at times impossible, to perform due to the risk of service interruption to local area load. The ability to perform routine and emergency maintenance on a facility, which supports nearly 2300 transfer directions, is paramount to the health and welfare of not only Wisconsin, but also the entire Midwest region.

3.7 Generation Alternatives

Although the addition of generation within eastern Wisconsin will help to achieve the LOLE criterion of 0.1 days per year, generation is not a viable alternative to a transmission reinforcement of the western interface because of the existing operating limitations. For years, secure operation of the western interface has only been viable through the extensive use of operating guides. One of those guides, the Arpin operating guide, opens lower voltage lines to keep them from exceeding their thermal capacities during an outage of any portion of the King – Eau Claire – Arpin – Rocky Run 345 kV line. Although the opening of the lower voltage facilities removes the thermal overloads, it does so at the expense of local load serving capability and reliability. Because of this, the Arpin operating guide is implemented only during the amount of time it takes operators to restore the 345 kV interconnection or to curtail transactions that contribute flow to the interface.

However, the existing western interface is so heavily burdened that the operating guide is called upon any time maintenance is required on the 345 kV interconnection, which severely reduces the ability to reliably serve local area load. In March of 1999, scheduled maintenance on the Arpin – Rocky Run 345 kV facility was cancelled because the Arpin operating guide would have been required even after the curtailment of transactions contributing to flow on the interface. In June of 1999, the Arpin – Rocky Run 345 kV line was removed from service to replace several poles because of their age and deteriorated condition. Once again, even after firm capacity transactions were curtailed, several lower voltage facilities overloaded and required the implementation of the Arpin operating guide. This condition resulted in a complete separation of eastern Wisconsin from western Wisconsin and severely compromised the ability to serve local area load in central Wisconsin. This situation is in direct violation of transmission planning standards adopted by NERC. NERC states in their 1997 Planning Standards document:

> *The transmission systems also shall be capable of accommodating planned bulk electric equipment maintenance outages and continuing to operate within thermal, voltage, and stability limits under the conditions of the contingencies as defined in Category B of Table I.* (p.9)

Although a portion of the Arpin guide is still required for the loss of the Arpin – Rocky Run 345 kV line after the addition of a second high voltage interconnection between Minnesota and central Wisconsin, it is only required at higher transfer levels. This will allow transmission operators the ability to curtail transactions to a safe level and open the existing 345 kV line without implementing the guide and without compromising local area load serving capability.

Additional generation within eastern Wisconsin will not improve the operational flexibility of the existing interface. In fact, depending on the location of the generation and the ultimate consumer of the generation, additional loading may surface on the existing Eau Claire – Arpin 345 kV facility, which will burden an already constrained interface. Power flow simulations show that moving energy from a generator in southeastern Wisconsin to northeastern Wisconsin will increase flow on the Eau Claire – Arpin 345 kV facility by

10.5% of the transaction.[9] In fact, generation located in southwestern Wisconsin that is consumed in northeastern Wisconsin will increase flow on the Eau Claire – Arpin 345 kV facility by 19.8% of the transaction.[10] Furthermore, additional eastern Wisconsin generation does little to improve the voltage and dynamic stability characteristics studied in the WIREs Phase II analysis unless the generation is on-line and running. This means that generation must be committed, at most times uneconomically, anytime a potential limitation is encountered. Once again, the location of the generation could actually exacerbate system limitations and lead to a reduction in overall system reliability.

The installation of additional generation within eastern Wisconsin will not eliminate the need to construct additional transmission facilities. Most generation added to the system requires expansion of the transmission system just to tie the generation to the bulk power grid. Generators of significant output, such as several hundred MWs, will likely require significant expansion of bulk power grid, including 345 kV facilities.

To further demonstrate the reasonableness of the expansion of the western interface, a present value revenue requirement (PVRR) analysis of satisfying Wisconsin's LOLE criterion with generation versus transmission was conducted. The amount of additional eastern Wisconsin generation required to maintain a 0.1 day/year LOLE criterion without the benefit of access to external generation resources via the transmission system was determined with the same data used by the WRAO's LOLE analysis. A combination of combined cycle/combustion turbine capacity was added within eastern Wisconsin until the 0.1 day/year criterion was met. The results are shown in Table 7 below.

[9] Source: NERC Generation Shift Factor calculator for transaction from WEC Paris generation to WPS West Marinette generation.

[10] Source: NERC Generation Shift Factor calculator for transaction from ALTE Nelson Dewey generation to WPS West Marinette generation.

Table 7 LOLE Analysis – CT/CC Capacity Added

CC/CT Capacity Added to Meet LOLE Criterion of 0.1 days/year

Line No.		1999	2000	2001	2002	2003	2004	2005	2006	2007
1a	Net Operable Generation Capacity at the Beginning of Each Year	11,005	12,729	13,704	13,704	13,704	13,844	14,024	14,284	14,464
1b	New Approved NUG Generation Installed by 6/1 of Each Year	179	750	-	-	-	-	-	-	-
1c	New Committed Utility-Owned Generation Operable by 6/1 of Each Year	155	225	-	-	-	-	-	-	-
1d	Total Operable Generation as of 6/1 of Each Year	11,339	13,704	13,704	13,704	13,704	13,844	14,024	14,284	14,464
1e	Projected Peak Demand Net of Interruptible Loads	10,215	10,374	10,582	10,757	10,953	11,161	11,387	11,573	11,754
1f	Reserve Margin Before Other Capacity Additions	11.0%	32.1%	29.5%	27.4%	25.1%	24.0%	23.2%	23.4%	23.1%
1g	Generation Added to Meet an 18% Reserve Margin	710	-	-	-	-	-	-	-	-
1h	CC/CT Capacity Added to Meet 0.1 day/year LOLE	680	-	-	-	140	180	260	180	240
1i	Total Capacity (1d + 1g + 1h)	12,729	13,704	13,704	13,704	13,844	14,024	14,284	14,464	14,704
1j	Reserve Margin After Total Capacity Additions	24.6%	32.1%	29.5%	27.4%	26.4%	25.7%	25.4%	25.0%	25.1%
	Cumulative Generation Capacity Added	1,724	2,699	2,699	2,699	2,839	3,019	3,279	3,459	3,699
1k	Row 1i Minus 118% of Row 1e = Total Gen above 18% to get 0.1 LOLE	675	1,463	1,217	1,011	919	854	847	808	834

Row 1k of Table 7 shows the amount of generation, in excess of the 18% reserve margin already maintained by Wisconsin utilities, that is necessary to achieve the 0.1 day/year criterion without the benefit of transmission interconnections to external regions. Row 1k demonstrates that through the year 2007, at least 800 MW of additional generation is required to maintain reliability if there is no access to external generation resources. An economic analysis was conducted to determine the PVRR of adding 800 MW of combustion turbine generation starting in 2003. This PVRR was then compared to the PVRR of building the Weston – Arrowhead 345 kV plan (which includes the cost of associated projects). The Weston – Arrowhead 345 kV plan is given a capacity and energy credit for reducing losses on the system. The methodology used to determine each PVRR accounted for both the capital cost of the facilities plus the operations impact of the facilities.

The following assumptions and data sets were utilized in the analysis:

1. Construction cost of Weston – Arrowhead project: $250 million in 2002 dollars.
2. Transmission construction cash flow: 12.5% in 2000, 38.0% in 2001, 41.0% in 2002, 8.5% in 2003.
3. Yearly O&M of Weston – Arrowhead 345 kV: $100,000 in 1999 dollars.
4. Loss savings of transmission line: As determined in WIREs Phase II
5. Capital cost of CT: from Advance Plan 8 ($293/kW in 1999 dollars).

6. WPS long range production cost analysis data set as a proxy for the Wisconsin capacity and energy market.
7. Economic characterization of transmission loss savings with WPS long range production cost analysis data set as a proxy for the Wisconsin capacity and energy market.
8. Study period: 30 years (2003 – 2032)

The results of the PVRR analysis are shown in the table below.

Table 8 PVRR Analysis – Generation vs. Transmission

Shortfall Energy Cost ($/MWh)			**Total PVRR ($M 2003)**		**Shortfall Energy Savings of Trans** ($M)	**PVRR Benefit of Trans** d-e+f ($M)
Sept – May	June	Jul – Aug	CT	Transmission		
a	b	c	d	e	f	g
25	45	65	93.2	58.7	0.0	34.6
50	90	130	75.5	57.0	25.3	43.8
100	180	260	40.0	53.6	75.9	62.3
100	500	1000	-122.7	36.9	319.3	159.7

Column g of the table shows the PVRR savings of the transmission reinforcement plan in relation to the generation option. Depending on the cost of shortfall energy (columns a – c), the transmission reinforcement option has a net PVRR benefit of approximately $35 – $160 million over the generation option.

Column d of Table 8 demonstrates that if the price of shortfall energy is relatively modest, the production cost savings of the generation option is not sufficient to overcome the large capital cost of building generation in excess of the 18% reserve margin. If the price of shortfall energy is relatively large, the production cost savings of the generation option will overcome the large capital cost and result in a negative PVRR (or a net cost savings of adding generation). Column e shows the PVRR of the transmission reinforcement option for the various shortfall energy costs. Because the loss savings associated with the transmission option is factored into the analysis, an increase in the price of shortfall energy results in a greater loss savings value, and subsequently, a lower PVRR. Column f of the table shows the production cost savings associated with the reduction of the shortfall energy cost due to unconstrained access to external markets via the transmission reinforcement.

This table shows that the PVRR of the generation option is heavily dependent on the tremendously uncertain cost of shortfall energy. Shortfall energy is the amount of energy supplied by the external marketplace to cover those times when generation is unavailable within eastern Wisconsin. Because eastern Wisconsin's access to external markets is constrained by the existing transmission system, the price of shortfall energy is at times very large. The production cost savings of additional generation within eastern Wisconsin are magnified as the price of shortfall energy is increased. This is because the reliance on the external marketplace is diminished as additional generation is added to eastern Wisconsin.

Conversely, uninhibited access to the external market made possible by a major transmission reinforcement such as the Weston – Arrowhead project, tends to discipline the shortfall energy price and results in an overall production cost savings. Although the reliance on the external marketplace for shortfall energy stays the same, the access to larger and more competitive markets drives the cost of the shortfall energy down. The production cost savings associated with uninhibited access to the external marketplace is shown in column f of the table. This column assumes that the transmission reinforcement reduces the price of shortfall energy to the lowest values in columns a-c.

Clearly, there is tremendous uncertainty about the future energy marketplace in general and shortfall energy prices in particular. This analysis considers multiple ranges of future shortfall energy prices and demonstrates that the transmission reinforcement is not unreasonable when compared to a generation-only reinforcement. In fact, under certain scenarios of shortfall energy prices, the transmission reinforcement alternative is highly attractive when compared with the generation option. The existing western interface, consisting of a single 345 kV line, is insufficient to sustain reliable transmission grid operations even if additional generation is installed in eastern Wisconsin. This fact leads to the conclusion that the Weston – Arrowhead transmission reinforcement plan is the best plan to address the reliability deficiencies of the Wisconsin energy system.

3.8 Conservation and Renewable Alternatives

As previously discussed, the Weston – Arrowhead 345 kV transmission reinforcement project is required to eliminate operational deficiencies with the existing western interface. Although the addition of generation resources within eastern Wisconsin will help to achieve the 0.1 days/year LOLE criterion, it will not address the operational limitations of a major 345 kV interface that requires the implementation of operation guides just to perform routine maintenance.

As demonstrated in the PVRR analysis of the combustion turbine alternative to transmission, it is difficult to increase eastern Wisconsin generation reserves beyond 18% to maintain reliability more economically than transmission interface expansion. Renewable generation alternatives, being several times more costly than combustion turbine technology, will yield the same relative economics. As evidenced in the generation expansion plans approved by the Commission in Advance Plan 8, renewable generation alternatives, although technically feasible, are not cost effective when compared to combined cycle and combustion turbine technologies.

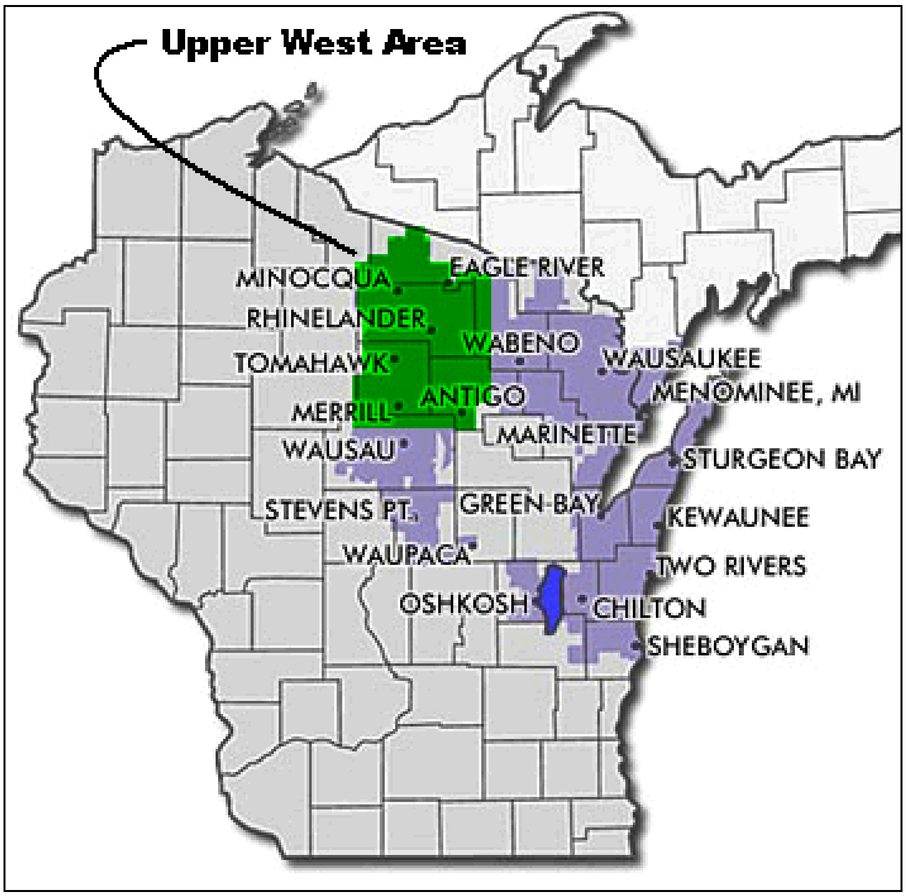
Conservation measures, through demand side management (DSM) programs, are not reasonable alternatives to the Weston – Arrowhead project. DSM, through a process known as targeted area planning (TAP), is often employed to target a particular customer group within a defined geographical location to reduce the demand for electrical capacity and energy. The Weston – Arrowhead project is required to restore adequate reliability and operating margins within a geographical region that encompasses several states, DSM alternatives, requiring significant time to modify customer habits that ultimately lead to an ultimate reduction in demand in very defined customer groups, are not viable tools to address regional reliability and operational issues. Even if DSM was capable of reducing load growth within the entire Midwest to zero, additional transmission infrastructure across the western interface is required to re-establish and maintain reliability margins within the bulk power system. As previously mentioned, the existing western interface is continually encumbered with operating restrictions just to maintain security of the system which is increasingly burdened with non-traditional uses. The current reliability benefit of the western interface is near zero and the only viable option to restore the reliability benefit is to expand the capability of the interface.

CHAPTER 4 TRIPOLI—HIGHWAY 8 STATEMENT OF NEED

4.1 Upper West Area Definition

The Upper West area is defined as the Wisconsin Public Service Corporation (WPSC) service territory north of Wausau, WI. Figure 11 highlights the Upper West area as it relates to the rest of the WPSC service territory.

Figure 11 Upper West Area

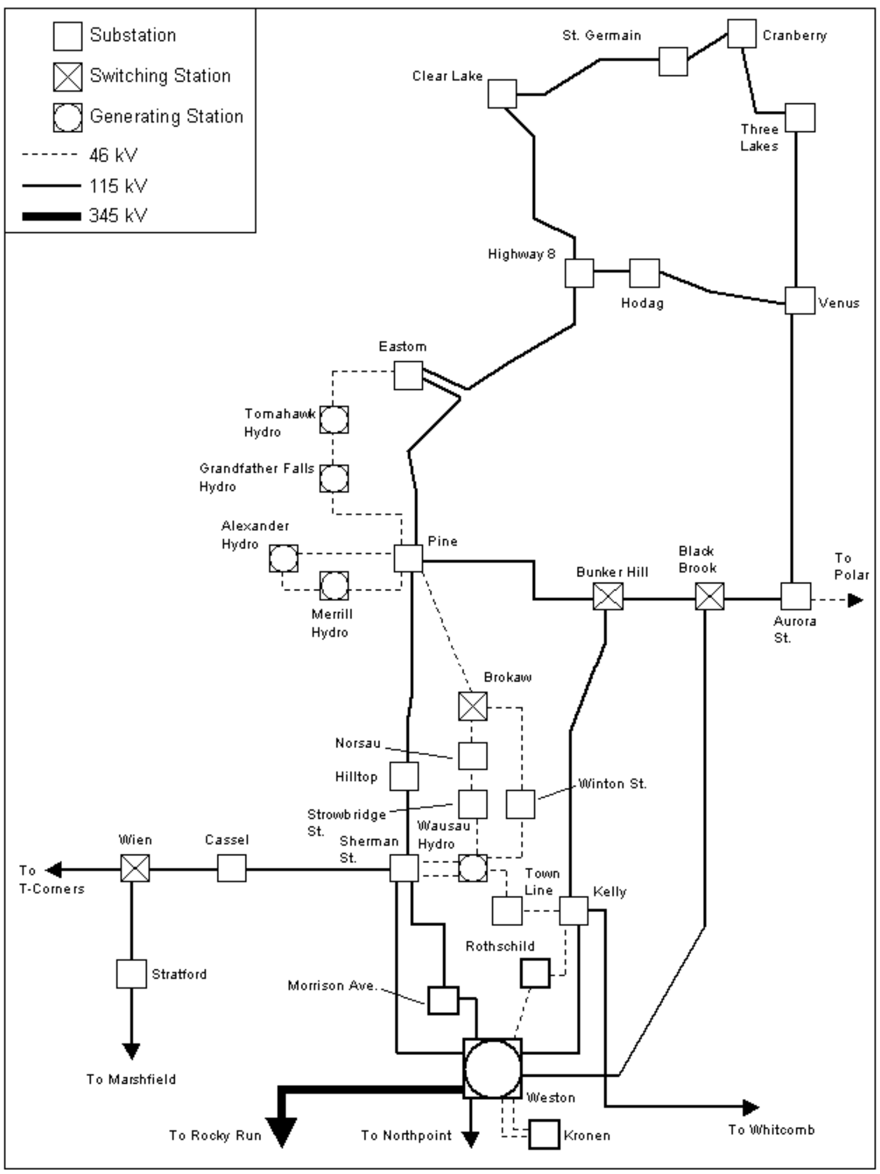


The Upper West 115 kV transmission system is primarily a 'figure eight' loop that provides service to several distribution substations spread throughout the area. The distribution substations provide service to the following Wisconsin communities and their surrounding areas: Antigo, Monico, Crandon, Three Lakes, Eagle River, St. Germain, Minocqua, Woodruff, Rhinelander and Tomahawk. In addition, the 115 kV transmission system also directly serves a large industrial customer in Rhinelander.

The Upper West 46 kV system between Tomahawk and Merrill supports several hydroelectric generating stations. The 46 kV system also directly serves a large industrial customer in Tomahawk.

The entire Upper West transmission system is supplied by three 115 kV lines emanating from the Wausau area. WPSC does have one interconnection with Alliant Energy via a 69 kV line terminating at Aurora St. substation in Antigo. The interconnection supports Alliant's 69 kV system and provides little or no support for WPSC's system. Figure 12 is a one-line diagram of the existing WPSC Wausau/Upper West transmission system.

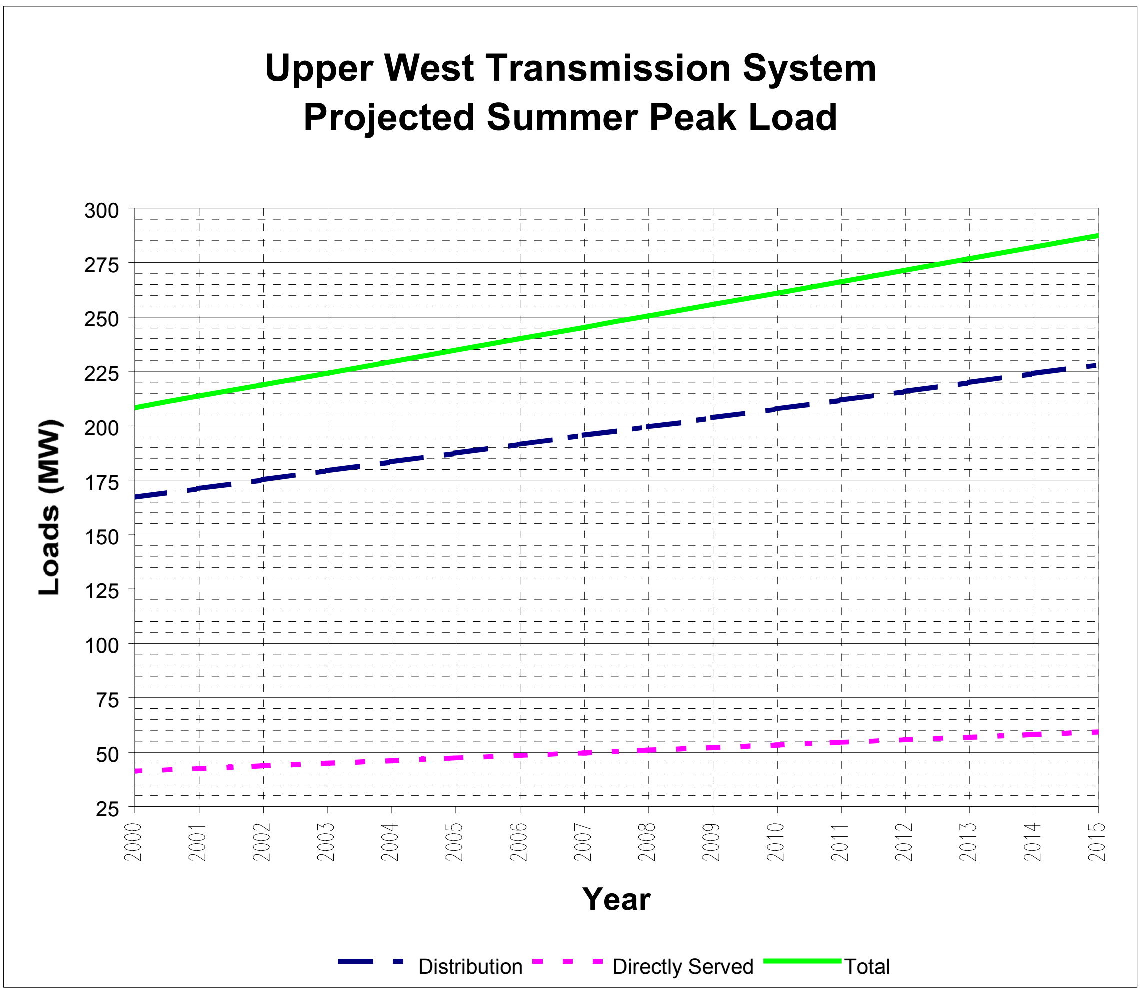
Figure 12 Wausau/Upper West Area Transmission System



4.2 Upper West Load Growth

Due to significant growth in the tourism industry, the Upper West area has seen steady growth in the residential and commercial customer sectors. Additionally, the load growth in the industrial sector has been significant as well with demand steadily increasing. This translates to increasing peak electric demands placed upon the Upper West transmission system. The load growth projections were developed through an evaluation of historical data collected for the region. Historical data indicates that the total summer peak demand on the Upper West transmission system has increased at a rate of approximately 2.5% annually. Based on the available space for development in the region, WPSC expects this load growth rate to continue. Figure 13 plots projected summer peak loads for the Upper West transmission system. The load projections account for both distribution system customers (< 25 kV) and customers directly served by the 46 kV and 115 kV systems.

Figure 13 Projected Upper West Loads



Appendix D contains additional information pertaining to the development of the Upper West area load projections.

4.3 Transmission System Limitations

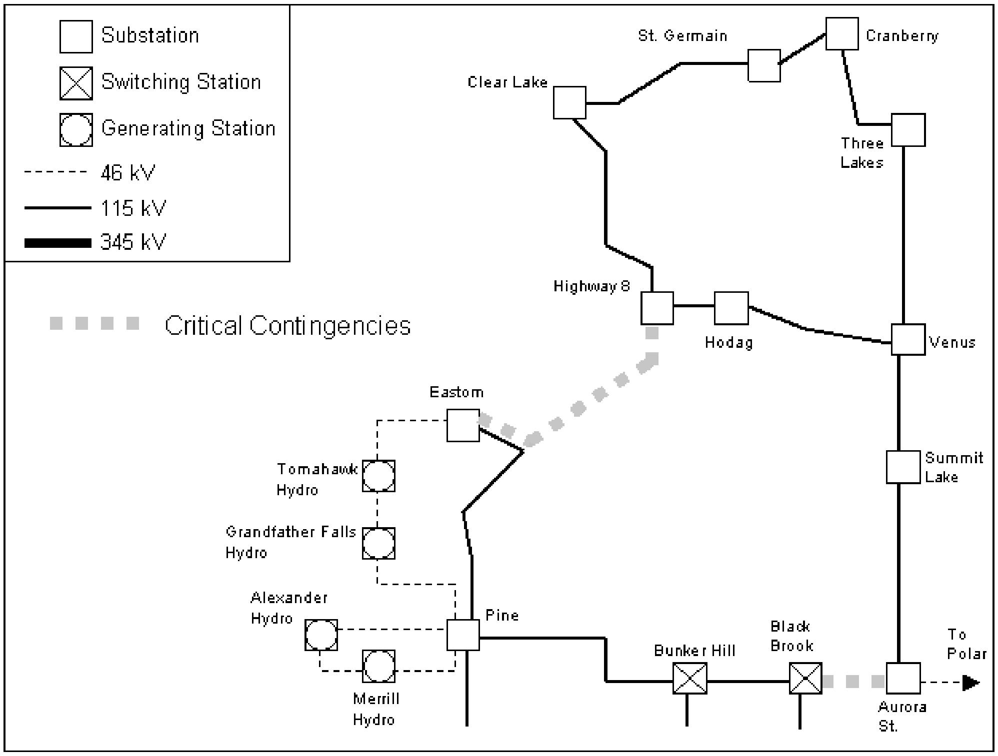
WPSC Plans for transmission system reinforcements based upon a single contingency criterion. The criteria requires that, during peak demand periods, a forced outage to any single transmission system component will not cause other facilities to overload or cause system voltages to fall below acceptable levels. Overloaded transmission system facilities may experience fatigue or failure due to excessive heat, while unacceptable voltages may cause an interruption of service or damage to customer equipment. The problems that develop in the Upper West are related to voltage control and the potential for voltage instability or collapse following a single contingency.

Voltage collapse occurs when the transmission system, combined with local generation, cannot provide enough reactive power to maintain adequate bus voltages in a region impacted by a system disturbance. The system voltages in a region uncontrollably fall to levels at which customer equipment is damaged or is tripped off-line by protective devices. Voltage collapse in a region can be total (blackout) or partial (brownout).

Voltage instability is a condition in which a portion of the bus voltages in an area fall to unacceptable levels. Load drops off-line and over a period of time the bus voltages in the area recover. When attempts are made to restore the load, bus voltages fall again and the load trips again. The cycle will continue until transmission system operators shed load to stabilize voltages.

Based on current load growth projections, WPSC expects the voltage stability concerns associated with single contingencies to develop by the 2003 summer peak demand period. A forced outage to the Black Brook—Aurora St. 115 kV line or a forced outage to the Eastom—Highway 8 115 kV line could cause voltage instability or collapse. Each critical line is highlighted in Figure 14.

Figure 14 Critical Upper West Contingencies



Time domain (dynamic) simulations that predict the voltage response of the transmission system following a Black Brook—Aurora St. outage can be found in Appendix D.

4.4 Transmission System Reinforcement Alternatives

Wisconsin Public Service Corporation evaluated six alternative transmission system projects to reinforce the Upper West system. Brief descriptions of each reinforcement alternative are listed below. Detailed descriptions and one-line diagrams depicting the reinforcement alternatives can be found in Appendix D.

4.4.1 TRIPOLI-HIGHWAY 8 PLAN

This reinforcement alternative solves the Upper West voltage stability problem by installing a substation under the proposed 345 kV Weston—Arrowhead transmission line near the town of Tripoli and constructing a 115 kV transmission line between Tripoli and the Highway 8 substation located on the west side of Rhinelander.

4.4.2 Distributed Superconducting Magnetic Energy Storage (D-SMES) Plan.

WPSC has entered into an agreement to purchase and install six D-SMES units at several substations in the Upper West area to protect the system from voltage instability and/or voltage collapse through the 2002/2003 winter. D-SMES units support the transmission system by rapidly releasing real and reactive power following a disturbance. This reinforcement alternative corrects the Upper West voltage stability problem through the purchase of additional D-SMES units as Upper West load continues to grow. Based on current load projections, two new units should be added every three years. Additional D-SMES units would be installed in 2003, 2004, 2006, 2007, 2009 and 2010. In order to meet the single contingency planning criteria though 2010, several 115 kV lines in the Upper West area would require reconstruction to relieve thermal limitations.

4.4.3 Parallel Circuit Plan.

This reinforcement alternative corrects the Upper West voltage stability problem by replacing critical line segments utilizing single circuit H-frame structures with parallel 115 kV lines constructed on single pole structures. The existing 115 kV transmission line between Black Brook switching station and Aurora St. substation would be replaced with parallel 115 kV circuits in a manner that minimizes new right-of-way acquisition. Black Brook switching station would be eliminated, and the transmission system reconfigured to create a Weston—Aurora St. line and a Bunker Hill—Aurora St. line. The existing 115 kV transmission line between Skanawan switching station and Highway 8 substation would be replaced with parallel 115 kV circuits in a manner that minimizes new right-of-way acquisition. This plan would also convert the 46 kV system between Merrill and Tomahawk to 115 kV operation. Skanawan switching station would be eliminated, and the transmission system reconfigured to create a Pine—Highway 8 line and an Eastom—Highway 8 line.

4.4.4 Black Brook—Venus 345 kV Plan.

This reinforcement alternative solves the Upper West voltage stability problem by constructing a new 345 kV transmission line between Black Brook switching station and Venus substation. The new line would be energized initially at 115 kV. The Bunker Hill—Black Brook 115 kV line would be rebuilt and Black Brook switching station removed to create a Weston—Venus line and a Bunker Hill—Aurora St. line.

The proposal for 345 kV construction is based upon the inclusion of Black Brook--Venus in future plans to strengthen the Wisconsin—Upper Peninsula transmission system interface (Advance Plan 8 Northeast Area Study - Technical Support Document D23p). All but six miles of the existing transmission line between Weston and Black Brook is built for 345 kV operation.

4.4.5 Black Brook—Venus 115 kV Plan.

This reinforcement alternative solves the Upper West voltage stability problem by constructing a new 115 kV transmission line between Black Brook switching station and Venus substation. The Bunker Hill—Black Brook 115 kV line would be rebuilt and Black Brook switching station expanded to sectionalize the Weston--Black Brook--Venus line and the Bunker Hill--Black Brook--Aurora St. line.

4.4.6 Prentice—Highway 8 Plan.

This reinforcement alternative solves the Upper West voltage stability problem by strengthening the Northern States Power/Dairyland Power Cooperative (NSP/DPC) 115 kV transmission system in central Wisconsin and linking it to the Upper West area. The construction of a 345/115 kV substation under the proposed 345 kV Weston—Arrowhead transmission line near the city of Ladysmith combined with a 115 kV transmission line between the new Ladysmith substation and NSP's existing Osprey substation would reinforce the NSP/DPC central Wisconsin system. The NSP/DPC system would then be tied to the Upper West by the construction of a Prentice--Highway 8 115 kV line.

4.5 Economic Analysis of Transmission System Reinforcement Alternatives.

The economic analysis calculated a present value revenue requirement (PVRR) for each reinforcement alternative. The PVRR calculation included the following components:

1.) Construction costs for new or rebuilt facilities to meet the WPSC single contingency criteria in the Upper West through the 2010 summer.
2.) Wausau 46 kV conversion alternatives.
3.) Routing of the Weston—Arrowhead 345 kV transmission line.
4.) Transmission system losses.

Table 9 summarizes the PVRR calculations for each reinforcement alternative. A detailed discussion of the PVRR components and their relation to each reinforcement alternative can be found in Appendix D.

Table 9 Present Value Revenue Requirement Calculations

Reinforcement Alternative	Present Value Revenue Requirement (PVRR)	
Tripoli--Highway 8 Plan	$	12,094,404
D-SMES Plan	$	17,616,987
Parallel Circuit Plan	$	19,048,300
Black Brook--Venus 345 kV Plan	$	24,057,734
Black Brook--Venus 115 kV Plan	$	13,322,855
Prentice--Highway 8 Plan	$	20,817,028

4.6 Generation Alternative

The Upper West transmission system could be supported by additional generation in the area. The system would be adequately supported through the 2010 summer by the installation of a 40 MW gas turbine. The generation alternative would have a present value revenue requirement of $20,088,354. Appendix D provides a breakdown of the costs included in the PVRR calculation for the generation alternative.

4.7 Conservation and Renewables

The implementation of conservation practices or the installation of distributed generation, possibly utilizing renewable resources, are generally considered Targeted Area Planning (TAP) alternatives to the construction of new transmission lines. Projects proposed in Advance Plan 8 to address the developing transmission system deficiencies in the Upper West area were screened for the potential use of TAP solutions. The screening process conducted in Advance Plan 8 determined that the load growth characteristics of the region precluded the implementation of a TAP solution. Additional discussion pertaining to TAP in the Upper West area, or other projects proposed in Advance Plan 8, can be found in the AP 8 Technical Support Document D23t-Targeted Area Planning Screening.

4.8 Conclusions

Table 10 summarizes the PVRR calculations and line miles of transmission construction / reconstruction associated with the Upper West area reinforcement alternatives.

Table 10 Upper West Reinforcement Alternative Summary Table

Reinforcement Alternative	Present Value Rate of Return (PVRR)	New Construction Line Miles (1)		Rebuilt Line Miles
		345 kV	115 kV	
Tripoli--Highway 8 Plan	$ 12,094,404	-	42	-
Black Brook--Venus 115 kV Plan	$ 13,322,855	-	40	8
D-SMES Plan	$ 17,616,987	-	-	59
Parallel Circuit Plan	$ 19,048,300	-	-	24
Generation Plan	$ 20,088,354	-	-	-
Prentice--Highway 8 Plan	$ 20,817,028	-	76	-
Black Brook--Venus 345 kV Plan	$ 24,057,734	40	-	8

(1) Facilities in addition to the Weston--Arrowhead 345 kV line.

Each reinforcement alternative meets the WPSC single contingency criteria through the 2010 summer based on current load projections for the area. WPSC prefers the implementation of the Tripoli—Highway 8 Plan to serve Upper West load for the following reasons:

1.) **Present Value Revenue Requirement.**
The Tripoli—Highway 8 Plan presents the lowest revenue requirement of all of reinforcement alternatives. Support of this plan is consistent with WPSC's practice of building the most efficient facilities in an effort to keep electric rates at a low level. The revenue requirement for the Tripoli—Highway 8 Plan is significantly lower than any other reinforcement alternative.

2.) **Geographic Diversity.**
The Tripoli—Highway 8 line provides a source to the area that is separate from the existing corridor that runs north from Wausau to Merrill and Antigo. This source from the west will protect against a scenario in which two critical circuits that serve the Upper West area are lost during a severe storm. Additionally, routing for the Tripoli—Highway 8 line will minimize the corridor it shares with existing transmission lines critical to load serving in the Upper West. Table 11 summarizes the right-of-way and corridor sharing associated with each reinforcement alternative that proposes to build new transmission lines.

Table 11 Shared Rights-of-Way and Corridors

Plan	Shared Right-of-Way (Miles)	Shared Corridor (Miles)	Parallel Facilities
Tripoli--Highway 8	10 (1)		Tripoli--Highway 8/Eastom--Highway 8
Black Brook--Venus 345 kV		30	Black Brook--Venus/Aurora St.--Summit Lake--Venus
Black Brook--Venus 115 kV		30	Black Brook--Venus/Aurora St.--Summit Lake--Venus
Parallel Circuit	24		Eastom--Highway 8/Pine--Highway 8, Weston--Aurora St./Black Brook--Aurora St.
Prentice--Highway 8	10 (1)		Prentice--Highway 8/Eastom--Highway 8

(1) This number could be reduced to 4 miles pending a decision on routes.

3.) **Long term (beyond 2010) needs of the Wausau Area transmission system.** The Wausau transmission system will face additional concerns not addressed in this application as electric demand continues to grow in the region. At this time transmission lines emanating from the Weston generating station serve the vast majority of Wausau/Upper West load. The addition of a new 115 kV source to the area will relieve flows on the existing facilities that tie the Weston generating station to the Wausau and Upper West transmission systems. Without a new tie line to the area, power flows out of Weston could require reinforcements to the following 115 kV lines:

Weston—Morrison Ave.—Sherman St.
Weston—Sherman St.
Weston—Kelly

4.) **Long term (beyond 2010) needs of the Upper West area transmission system.** The combination of the Tripoli—Highway 8 Plan with the Weston—Arrowhead 345 kV line presents an opportunity to significantly reinforce the Upper West transmission system. The addition of this tie will allow future limitations to be addressed by the expansion or reconstruction of existing facilities in Upper West area. Expansion of the existing facilities at this time would require the construction of a tie line in the future.

Failure to account for the Upper West load serving benefits when routing the Weston—Arrowhead line could result in a 345 kV route that runs west, from Weston to the Owen area and northwest to the Ladysmith area. The present value analysis of the Upper West reinforcement alternatives shows that construction of a tie line to the Upper West area from Ladysmith is not the most efficient solution (Prentice—Highway 8 Plan vs. Tripoli—Highway 8 Plan).

One plan, Black Brook—Venus 345 kV, proposes to reinforce the Upper West transmission system with the possibility for expansion to the east. The Advance Plan 8 Northeast Area Study (Technical Support Document D23p) identified the need to add a second 345 kV transmission line emanating from Michigan's Upper Peninsula following the eventual shut down of the Empire and Tilden mines. The new line would be necessary to maximize the use of available generating capacity at the Presque Isle Power Plant, located near Marquette, MI. One alternative to provide the generation outlet is a Presque Isle—Plains (Iron Mountain, MI)—Venus—Black Brook—Weston 345 kV line. All but six miles of the existing Weston—Black Brook line is built for 345 kV operation. An extension of the 345 kV line to Venus would allow for the combination of plans to satisfy the long term Upper West load serving needs and the Upper Peninsula generation outlet need. Construction of Black Brook—Venus with 115 kV specifications would limit the options for a tie line from the Upper West to the east due to the fact that a 115 kV line will not satisfy the Presque Isle export requirements. Wisconsin Public Service Corporation would rank this alternative as the second most desirable behind Tripoli—Highway 8.

Other alternatives (D-SMES Plan, Parallel Circuit Plan, and Generation Plan) have no provisions for future tie lines to systems outside of the Upper West/Wausau transmission system. Each plan is limited in scope when future considerations are taken into account.

5.) "Must Run" Generation Concerns.

The installation of a generator to address local load serving concerns in the Upper West area would require the assignment of "must run" status to the unit. As loads continue to grow, the hours of operation required by the generator increases. To adequately protect the Upper West transmission system, the generator would have to be on-line when total Upper West load exceeded 220 MW. Figure 15 depicts a typical load duration curve for the Upper West area between June 1 and August 31. The curve is normalized to the summer peak load. Table 12 compares the 220 MW load level to the projected summer peak load in the Upper West area and, using Figure 15, predicts the hours of "must run" generation required to protect the Upper West transmission system during each summer through 2010.

Figure 15 Upper West Load Duration Curve

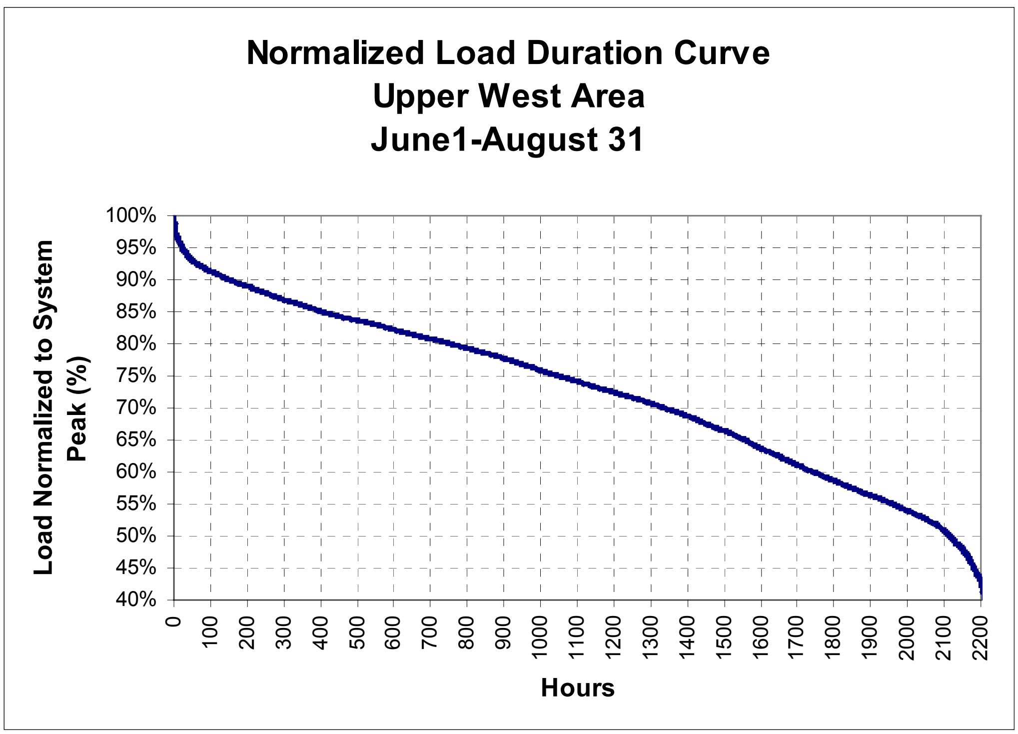


Table 12 Upper West "Must Run" Generation Requirements

Year	Projected Upper West Peak Load	220 MW Load Level as a % of the Summer Peak	Hours of "Must Run" Generation Required
2003	224	98.1%	5
2004	230	95.9%	15
2005	235	93.7%	38
2006	240	91.7%	86
2007	245	89.7%	165
2008	251	87.8%	257
2009	256	86.0%	353
2010	261	84.3%	449

This figure and table demonstrate that the "must run" generation hours escalate rapidly over time. Typically, it is only efficient to run small gas turbines for 100-200 hours in a summer. Considering that Table 12 only accounts for summer operation of "must run" generation, the use of generation for Upper West load serving support would be inefficient and uneconomical as early as 2007.

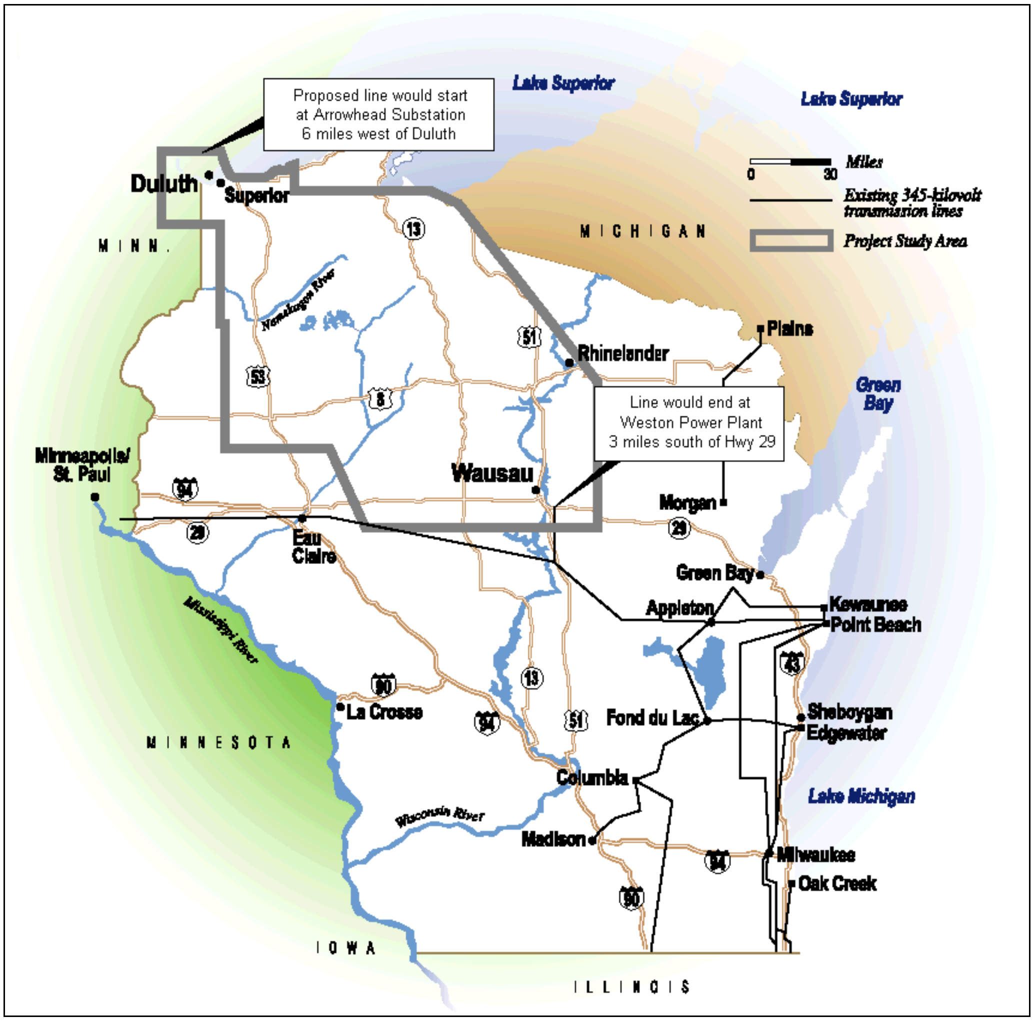
CHAPTER 5

ROUTING OVERVIEW

Having established the objective of constructing a 345-kV connection between the Weston Power Plant near Wausau, Wisconsin and the Arrowhead Substation near Duluth, Minnesota, the next phase of the project was to identify alternative routes to accomplish this goal. The following is an overview of the steps involved in the identification of alternative routes.

The first step was to establish the boundaries of the study area. The study area is shown in Figure 16.

Figure 16 Arrowhead—Weston Project Study Area



The area contains parts of 17 counties. After establishing the study area, the next step was to identify potential route alternatives. The objective of the routing analysis was to find the route that offers the most benefits in terms of providing reliable and economic electric power, while minimizing adverse impacts on the social and natural environment. In addition to the Weston to Arrowhead 345-kV line, the route identification included identifying routes for a 115-kV line to serve local needs in Rhinelander, Wisconsin. Those routes originated from the Tripoli area in Lincoln County, where a new substation is proposed to tap the 345-kV line. The effort to identify routes included three main components, listed below:

1. Field reconnaissance of the study area
2. Review of United States Geological Survey (U.S.G.S) topographic maps and aerial photography
3. Contacts with local, state, and federal resource agencies

Based on this input, the project team identified routes that would connect Weston to Arrowhead and Tripoli to Rhinelander without creating significant adverse impacts to natural or human resources. The major concerns in the routing were avoiding communities, existing homes, wetlands, and other sensitive resources.

In order to minimize impacts, the project team tried to identify routes that follow existing corridors such as transmission lines, pipelines, railroads and road rights-of-way. The routes consist of individual segments that may be combined in different arrangements to connect one endpoint to the other. The initial network of alternatives consisted of over 500 individual segments that could be combined to form different routes between the various substations.

The initial network of segments included routes from Weston through Tripoli and north through Ashland County, then west to Arrowhead. This set of alternatives was dropped because of both environmental and social conflicts. Any route that would cross diagonally through the Chequamegon National Forest would have to avoid major lakes such as Moose Lake, Namekagon Lake, and Lake Owen. In addition, the national forest contains primitive and semi-primitive areas that were considered sensitive areas to avoid. These areas include the Rainbow Lake and Porcupine Lake Wilderness Areas, and seven semi-primitive areas. The national forest is not all federally owned land however. Private in-holdings are scattered throughout the forest. These in-holdings are heavily developed with cabins and permanent homes. Heavy concentrations of homes occur around the communities of Clam Lake, Namekagon and Delta.

Avoiding the National Forest resulted in longer routes that still had relatively high social impacts. These routes basically followed the railroad corridor north toward Ashland and then west to Superior. The routes passed through or near the towns of Phillips, Park Falls, Glidden, Mellen, and Iron River. These routes offered limited opportunities for corridor sharing because the railroad passes directly through most of the towns and there are few existing transmission corridors to follow. In addition, routes to the northeast have less potential to provide future electrical benefits to the state than routes on the west side of the study area. Compared to the western options to Superior, the northeast routes were considered less desirable and were therefore dropped from further consideration.

In order to determine community values relative to the proposed project, the route selection process included two forms of public input. One form was contacts with public officials. WPS and MP staff contacted local officials in each town crossed by a route. They also contacted county foresters and met with city and county boards.

The other form of public involvement was public meetings held by WPS and MP, and subsequent comments received as a result of these meetings. Fourteen public meetings (two meetings in seven towns) were held in Wisconsin to explain the project and gather public input. All of the remaining possible routes were shown on aerial photographs and U.S.G.S. topographic maps. Participants received a written questionnaire to communicate their opinions on the route locations and issues of concern to them regarding the project. This input was useful in determining the values and attitudes of the residents regarding the alternative routes and to gather individual input on potential impacts. The public involvement activities are summarized in Appendix A. The public input lead to the addition of some new segments, adjustments to some segments, and the deletion of others.

The state and federal agencies provided input on threatened and endangered species, cultural resources, wetlands, airports, and highway projects. Copies of agency correspondence are included in Appendix A.

Following the public meetings, the project team reviewed all of the input on alternatives. They dropped some segments that had higher impacts, added some segments to avoid sensitive areas, and adjusted segments to reduce potential impacts. The final network of possible segments, combined to form several proposed routes, can be found in Appendix A.

Detailed project cost estimates, developed from the list of proposed routes, can be found in Appendix B.